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Transcript Exhibit(s)

Docket #(s): G-01551A-10-0458

Arizona Corporation Commission
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To: Docket Control

Date: August 17, 2011

Re: Southwest Gas Corporation / Rates
G-01551A-10-0458
August 10, 12, and 15, 2011
Volumes I through III, Concluded

STATUS OF ORIGINAL EXHIBITS

FILED WITH DOCKET CONTROL

Arizona Investment Council (AIC Exhibits)

1 through 3

Cynthia Zwick (Zwick Exhibits)

1 and 2

Natural Resource Defense Council (NRDC Exhibits)

1 and 2

Residential Utility Consumer Office (RUCO Exhibits)

1, 2, 3 (Administrative Notice), 4 through 16

Southwest Energy Efficiency Project (SWEEP Exhibits)

1 and 2

Southwest Gas Corporation (A Exhibits)

1 through 18

Please note, to comply with Docket Control's filing requirements, we removed Exhibits A-1 through A-13 from binders. We removed and made copies of any tabs included within the exhibits.

Staff (S Exhibits)

1, 3, 5 through 9, 11, 12

CORRECTIONS TO INDEX OF EXHIBITS

Please see attached corrected page 512. Under the column "No.", Line 17.5 has been corrected from RUCO-3 to RUCO-4. Line 18.5 has been corrected from RUCO-4 to RUCO-5. Only the column "No." needed correction. We apologize for the inconvenience.

EXHIBITS RETURNED TO PARTIES

Residential Utility Consumer Office (RUCO Exhibits)

17	Not admitted

EXHIBITS NOT UTILIZED
Not given to Court Reporter

Staff (S Exhibits)

10

CONFIDENTIAL EXHIBITS
Given to ACALJ Nodes

Staff (S Exhibits)

2 and 4

Copy to:

Mr. Dwight D. Nodes, ACALJ
Mr. Justin Lee Brown, Southwest Gas Corp.
Ms. Robin Mitchell, Staff
Mr. Daniel Pozefsky, RUCO
Mr. Michael M. Grant, AIC
Mr. Timothy Hogan, SWEEP
Mr. Timothy Sabo, TEP
Ms. Laura E. Sanchez, NRDC
Ms. Cynthia Zwick

BEFORE THE ARIZONA CORPORATION COMMISSION

GARY PIERCE
Chairman
BOB STUMP
Commissioner
SANDRA D. KENNEDY
Commissioner
PAUL NEWMAN
Commissioner
BRENDA BURNS
Commissioner

IN THE MATTER OF THE APPLICATION OF SOUTHWEST GAS CORPORATION FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS PROPERTIES THROUGHOUT ARIZONA	)	DOCKET NO. G-01551A-10-0458

DIRECT

TESTIMONY

OF

ROBERT G. GRAY

EXECUTIVE CONSULTANT III

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JUNE 10, 2011

ALL-STATE LEGAL®
EXHIBIT
S-5

TABLE OF CONTENTS

SCHEDULES

EXECUTIVE SUMMARY
SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-10-0458

My testimony in this proceeding addresses the issues of gas procurement, the purchased gas adjustor, Southwest Gas Corporation's efforts to improve communications with its customers, the Payson Natural Gas Study, and rules and regulations for Southwest.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Robert G. Gray. I am an Executive Consultant III employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as an Executive Consultant III.

A. In my capacity as an Executive Consultant III, I conduct analysis and provide recommendations to the Commission on a variety of electricity, natural gas, and water/wastewater matters. A copy of my resume is attached as Exhibit RGG-1.

Q. What is the scope of this testimony?

A. This testimony will address gas procurement, the purchased gas adjustor, Southwest Gas Corporation's ("Southwest" or "Company") efforts to improve communications with customers, the Payson Natural Gas study, and rules and regulations for Southwest.

GAS PROCUREMENT

Q. Please discuss Southwest's natural gas procurement activities.

A. Southwest purchases large volumes of natural gas in the San Juan supply basin in northwestern New Mexico and the Permian basin in west Texas. The natural gas is then transported to Southwest's distribution system in Arizona via the El Paso Natural Gas Company ("El Paso") and Transwestern Pipeline ("Transwestern") interstate pipeline systems.

Q. Please discuss your review of Southwest's procurement activities.

A. The procurement review in Southwest's previous rate case covered the period of September 2004 through April 2007. Thus, this procurement review will cover the period of May 2007 through the end of the test year, June 2010. The review involves the following topics:

1. An overview of Southwest's system and the purchased gas adjustor;
2. Market conditions during the review period;
3. Southwest's monthly Purchased Gas Adjustor ("PGA") accounting during the review period;
4. Purchases during three months, April 2008, August 2009, and January 2010;
5. Southwest's use of financial instruments;
6. Compressed natural gas purchases by Southwest; and
7. A comparison of Southwest's purchases for core and noncore customers.

Q. Have you prepared a gas procurement review report?

A. Yes. Attached as Exhibit RGG-2 is Staff's review of Southwest's gas procurement activities during the period of May 2007 through June 2010.

Q What findings and recommendations does the Staff review contain?

A. Staff finds that Southwest's procurement activities from May 2007 through June 2010 are prudent. Staff recommends that in all Annual Gas Procurement Plans filed by Southwest, there be a separate section of the report providing a detailed explanation and documentation of the use of financial instruments by Southwest and in particular the swaps used by Southwest. Staff also recommends that Southwest provide an explanation in any future PGA report when it begins to recover compressed natural gas ("CNG") costs

Q. What additional information is Staff proposing that Southwest provide in its monthly PGA reports?

A. Staff is not requesting Southwest to provide any additional data or conduct any additional calculations in the monthly PGA reports. Southwest's reports, and particularly the pages containing the natural gas commodity and interstate pipeline cost information, use a wide variety of terms to describe various costs and other inputs. Over time Southwest changes, adds, and deletes certain terms, and in the past the Company has not noted in the report why terms are added, changed, or deleted or the meaning of new terms. For example, in recent years there have been significant changes in the charges paid by Southwest to El Paso Natural Gas Company for interstate pipeline service, with new line items appearing and disappearing at various times in the interstate pipeline cost section of the report. Staff believes that information would be not be burdensome to Southwest, and would help the Commission more easily understand the information contained in Southwest's monthly PGA report. Therefore, Staff recommends that each time Southwest adds, deletes, or changes specific terms used in its monthly PGA report, it provide an explanation of the change and a definition if the term is new or changed, in the cover letter of that given monthly PGA report. Southwest has indicated in response to a Staff data request that it would not object to providing this information in its monthly PGA reports. To begin this process, Staff further recommends that Southwest file in this docket, within 60 days of the final decision in this case, a document defining each current line item in its monthly PGA report. This would provide a clear starting point for Southwest to then define future changes to terminology used in the monthly PGA report.

PAYSON NATURAL GAS SERVICE EXTENSION STUDY

Q. Did ACC Decision No. 70665 (December 24, 2008) in Southwest's last rate case address the possibility of Southwest extending natural gas service to the Payson, Arizona area?

A. Yes. The order found that "Given the Company's willingness to prepare and submit a study regarding providing service to the Payson area, we find that Southwest Gas shall file such a study or report within 180 days of the effective date of this Decision." (p.56, lines 23-25). The Commission's interest in such a study was the result of several concerns with the current propane service in the Payson, Arizona area by Semstream Arizona Propane, including high prices and billing difficulties.

Q. Did Southwest file a study, pursuant to Decision No. 70665?

A. Yes. On June 15, 2009, Southwest filed a study in the previous rate case docket, which is Docket No. G-01551A-07-0504.

Q. Please discuss the genesis of the Commission's request for Southwest to file this report.

A. There had been several concerns with Semstream Arizona Propane's service in the Payson area, including a significant increase in rates as a result of higher propane prices, as well as billing problems which resulted in longer than normal billing cycles for some customers. Interest in possible natural gas service in Payson was spurred by the lower cost per therm of natural gas in comparison to propane. Amongst other actions, the Commission held a town hall in Payson on March 18, 2008, where public officials and Semstream customers expressed various concerns and questions regarding Semstream. Following the town hall, Staff was directed to prepare a report addressing a number of questions which were raised at the March 18, 2008 town hall as well as in other forums.

Q. Did Staff prepare this report?

A. Yes.

Q. Are you the Robert Gray who prepared the Staff Report dated May 22, 2008, which addressed a number of issues related to propane service in Payson, including the possibility of natural gas service being extended to Payson?

A. Yes. The May 22, 2008 Staff Report addressed eight questions in regard to propane service in Payson, one of which specifically addressed the possibility of extending natural gas service to Payson by either Southwest or UNS Gas. Attached is Exhibit RGG-2, which is Staff's answer to the question of what the possible service alternatives for propane customers in Payson are. Staff's consideration of natural gas service options in this Staff Report represents an initial consideration of the issue, while Southwest's June 15, 2009 study provides a more comprehensive analysis.

Q. Please briefly summarize the Staff and Southwest Gas reports.

A. Both Staff and Southwest found that there were significant barriers to extending natural gas service to Payson. Significant barriers to such an extension include:

1. The long distance from existing natural gas infrastructure, in excess of 50 miles.
2. The rugged terrain and environmental concerns resulting from a pipeline being run through Wilderness and National Forest lands.
3. The high cost of the project, including the initial pipeline and facility changes in the Payson area, by Southwest's estimate \$97 million initially and \$49 million over the following 9 years. The total customer base in Payson is relatively small to spread this amount of cost over, resulting in Payson residents paying significantly more for natural gas service than they currently pay for propane service.

4. Semstream Arizona Propane currently holds the Certificate of Convenience and Necessity to serve the Payson area, and it is not clear if Semstream would want to sell its Payson Division or what the cost of such a purchase would be if another entity such as Southwest were to extend natural gas service to the area.
5. Service to Semstream Arizona Propane's satellite systems, which currently receive propane service, despite not being connected to the central distribution system in Payson, would somehow have to be addressed.
6. Possible liquid natural gas service to Payson is not feasible due to the very high cost of liquefaction and regasification facilities, as well as other issues.

Q. What are your conclusions regarding Southwest's June 15, 2009 report as well as the possibility of extending natural gas service to Payson?

A. Southwest's study presents a reasonable perspective on the issue and fulfils Southwest's commitment to conduct such a study made in the previous rate case. Staff does not believe extension of natural gas service to Payson is viable for the reasons cited above, absent some major change of circumstances.

CUSTOMER COMMUNICATION IMPROVEMENT EFFORTS

Q. Please discuss the need for improvements in customer communications by Southwest.

A. In February 2011, Southwest experienced significant customer outages in southern Arizona, with approximately 14,000 customers in the Tucson area and 4,500 customers in the Sierra Vista area losing service. There were numerous concerns, during and after the outages, with both the information provided by Southwest regarding the outages and the methods of communication used by Southwest to inform the communities and customers impacted by the outages. On April 6, 2011 and April 7, 2011, the Commission held town hall meetings in southern Arizona to discuss the outages with the public.

Q. Has Southwest provided any information to Staff in this case regarding its efforts to improve communications with its customers?

A. Yes. In response to Staff Data Request STF-12-18 (attached as Exhibit RGG-4), Southwest identified a number of efforts it is undertaking to improve communications with customers. Southwest identifies a number of improvements it is pursuing, including the following items:

1. Creation of Facebook and Twitter accounts,
2. Development of an Outage Mapping System to show areas impacted by outages, number of affected customers, and outage restoration efforts,
3. Utilization of multiple off-site servers to provide server redundancy and thus greater reliability for Southwest's website,
4. Use of reverse 911 calling in coordination with the counties, recognizing its limitations, and
5. Development of predictive dialing to provide customers with contact and other applicable information.

The Company notes that its efforts to improve communications with its customers are on-going.

Q. What is Staff's perspective on Southwest's efforts to improve communications with its customers, as detailed in Exhibit RGG-4?

A. Staff believes that Southwest's efforts to date show promise of improved communications with its customers, but that a number of the improvements are still in development and thus Southwest's overall communications plan for its customers in the future is still at least somewhat unclear. One technology which Southwest did not identify as part of its efforts to improve communications with its customers is cell phone texting. Therefore, Staff believes that Southwest should investigate the use of texting as a further way the Company can communicate with its customers.

Q. In light of this, does Staff have any recommendations regarding this issue?

A. Yes. Staff recommends that Southwest file a report every six months in this docket, beginning on March 31, 2012, detailing developments in its efforts to improve communications with its customers. This will provide the Commission with on-going information on Southwest's improvements to its content on and systems for communicating with its customers. Staff further recommends that Southwest report to the Commission in its March 31, 2012 report, regarding whether the Company can use texting to communicate with its customers, or if it can't, provide an explanation as to why not.

RULES AND REGULATIONS

Q. Have you reviewed Southwest's proposed Rules and Regulations in this case?

A. Yes.

Q. Please describe Southwest's proposed Rules and Regulations in this case.

A. Southwest's only proposed change to its Rules and Regulations in this case is on page 208, in Rule No. 7, Provision of Service, where additional detail is being added as to who customers should contact in case of an emergency.

Q. Do you have any objection to this proposed change?

A. No.

SUMMARY OF RECOMMENDATIONS

Q. Please summarize your findings and recommendations.

A. My testimony includes the following findings and recommendations:

Gas Procurement

1. Staff recommends that in all Annual Gas Procurement Plans filed by Southwest, there be a separate section of the report providing a detailed explanation and documentation of the use of financial instruments by Southwest, and in particular the swaps used by Southwest.
2. Staff further recommends that Southwest provide an explanation in any future PGA report when it begins to recover CNG costs for serving a given area through the PGA mechanism, indicating the reason(s) for such service, expected length such service will be necessary, and estimated cost and volume of such service.

Purchased Gas Adjustor

3. Staff further recommends that each time Southwest adds, deletes, or changes specific terms used in its monthly PGA report, it provide an explanation of the change and a definition if the term is new or changed, in the cover letter of that given monthly PGA report.
4. Staff further recommends that Southwest file in this docket, within 60 days of the final decision in this case, a document defining each current line item in its monthly PGA report.

Customer Communication Improvement Efforts

5. Staff further recommends that Southwest file a report every six months in this docket, beginning on March 31, 2012, detailing developments in its efforts to improve communications with its customers.

6. Staff further recommends that Southwest report to the Commission in its March 31, 2012 report, regarding whether the Company can use texting to communicate with its customers, or if it can't, provide an explanation as to why not.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

Exhibit RGG-1

RESUME

ROBERT G. GRAY

Education

B.A. Geography, University of Minnesota-Duluth (1988)
M.A. Geography, Arizona State University (1990) Thesis: *A Model for Optimizing the Federal Express Overnight Delivery Aircraft Network.*

Employment History

Arizona Corporation Commission, Utilities Division, Phoenix, Arizona: Executive Consultant III (November 2007 – present), Public Utility Analyst V (October 2001 – November 2007), Senior Economist (August 1997 – October 2001), Economist II (June 1991 - July 1997), Economist I (June 1990 - June 1991). Conduct economic and policy analyses on a variety of natural gas issues in Arizona, including gas procurement, rate design, interstate pipeline issues, revenue decoupling, energy conservation, low income issues, natural gas research and development funding, customer services issues, special contracts, various tariff matters, and other natural gas issues. Conduct economic and policy analyses on a variety of electricity issues in Arizona, power plant and transmission line siting cases, energy efficiency, renewable energy standards, rate design, time-of-use service, and low income issues. Prepare recommendations and present written and oral testimony before the Commission and organize workshops and other proceedings on various utility industry issues. Represent the ACC in natural gas proceedings at the Federal Energy Regulatory Commission, at the North American Energy Standards Board, and on the National Association of Regulatory Utility Commissioners' Staff Subcommittee on Gas, including serving as a past Vice-Chair and Chair of the NARUC Staff Subcommittee on Gas.

Testimony

Resource Planning for Electric Utilities, (Docket No. 0000-90-088), Arizona Corporation Commission, 1990.

Citizens Utilities Company, Electric Rate Case (Docket No. E-1032-92-073), Arizona Corporation Commission, 1993.

Resource Planning for Electric Utilities, (Docket No. 0000-93-052), Arizona Corporation Commission, 1993.

Arizona Public Service Company, Rate Settlement (Docket No. E-1345-94-120), Arizona Corporation Commission, 1994.

U S West Communications, Rate Case (Docket No. E-1051-93-183), Arizona Corporation Commission, 1995.

Citizens Utilities Company, Electric Rate Case (Docket No. E-1032-95-433), Arizona Corporation Commission, 1996.

Resource Planning for Electric Utilities (Docket No. U-000-95-506), Arizona Corporation Commission, 1996.

Southwest Gas Corporation, Natural Gas Rate Case (Docket No. U-1551-96-596), Arizona Corporation Commission, 1997.

Black Mountain Gas Company - Northern States Power Company, Merger (Docket Nos. G-03493A-98-0017, G-01970A-98-0017), Arizona Corporation Commission, 1998.

Black Mountain Gas Company – Page Division Rate Case (Docket Nos. G-03493A-98-0695, G-03493A-98-0705), Arizona Corporation Commission, 1999.

Graham County Utilities Company Rate Case (Docket No. G-02527A-00-0378), Arizona Corporation Commission, 2000.

Black Mountain Gas Company – Cave Creek Division Rate Case (Docket No. G-03703A-00-0283), Arizona Corporation Commission, 2000.

Southwest Gas Corporation, Natural Gas Rate Case (Docket No. G-01551A-00-0309), Arizona Corporation Commission, 2000.

Black Mountain Gas Company – Page Division Rate Case (Docket Nos. G-03493A-01-0263), Arizona Corporation Commission, 2001.

Duncan Rural Services – Natural Gas Rate Case (Docket No. G-02528A-01-0561), Arizona Corporation Commission, 2001.

Toltec Generating Facility Application Before the Arizona Power Plant and Line Siting Committee (Docket No. L-00000Y-01-0112), September 2001.

Lap Paz Generating Facility Application Before the Arizona Power Plant and Line Siting Committee (Docket No. L-00000AA-01-0116), December 2001.

Bowie Generating Facility Application Before the Arizona Power Plant and Line Siting Committee (Docket No. L-00000BB-01-0118), December 2001.

Southwest Gas Corporation, Acquisition of *Black Mountain Gas Company (Docket* No. G-01551A-02-0425), Arizona Corporation Commission, 2002.

Wellton-Mohawk Generating Facility Application Before the Arizona Power Plant and Line Siting Committee (Docket No. L-00000Z-01-0114), February 2003.

Arizona Public Service Company, Rate Proceeding (Docket No. E-01345A-03-0437), Arizona Corporation Commission, 2004.

Graham County Utilities Company Rate Case (Docket No. G-02527A-04-0301), Arizona Corporation Commission, 2004.

Southwest Gas Corporation, Rate Proceeding (Docket No. G-01551A-04-0876), Arizona Corporation Commission, 2004.

Southern California Edison, Devers – Palo Verde 2 Transmission Line Application before the Arizona Power Plant and Line Siting Committee, (L-00000A-06-0295-00130), 2006.

Semstream Arizona Propane Acquisition of Energy West (Docket G-02696A-06-0515), Arizona Corporation Commission, 2006.

UNS Gas Inc., Rate Proceeding (Docket No. G-04204A-06-0463), Arizona Corporation Commission, 2007.

Semstream Arizona Propane Acquisition of Black Mountain Gas Company – Page Division (Docket G-03703A-06-0694), Arizona Corporation Commission, 2007.

Northern Arizona Energy, LLC, Northern Arizona Energy Project Application before the Arizona Power Plant and Line Siting Committee, (L-00000FF-07-0134-00133), 2007.

Arizona Public Service, Palo Verde Hub to North Gila 500 kV Transmission Lint Project Application before the Arizona Power Plant and Line Siting Committee, (L-00000D-07-0566-00135), 2007.

Southwest Gas Corporation, Rate Proceeding (Docket No. G-01551A-07-0504), Arizona Corporation Commission, 2008.

Arizona Solar One, LLC, Solana Generating Station and Gen-Tie Application before the Arizona Power Plant and Line Siting Committee, (L-00000GG-08-0407-00139 and L-00000GG-08-0408-00140), 2008.

Coolidge Power Corporation, Coolidge Power Project Application before the Arizona Power Plant and Line Siting Committee, (L-00000HH-08-0422-00141), 2008.

UNS Gas Inc., Rate Proceeding (Docket No. G-04204A-08-0571), Arizona Corporation Commission, 2009.

El Paso Natural Gas Company, Rate Proceeding (Docket No. RP08-426), Federal Energy Regulatory Commission, 2009.

Arizona Water/Global Water CC&N Extension/Acquisition Proceeding (Docket No. W-01445A-06-0199), Arizona Corporation Commission, 2009.

Graham County Utilities Company Rate Proceeding (Docket No. G-02527A-09-0088), Arizona Corporation Commission, 2009.

Publications

(with David Berry, Kim Clark, Lewis Gale, Barbara Keene, and Harry Sauthoff) Staff Report on Resource Planning. (Docket No. U-0000-90-088) Arizona Corporation Commission, 1990.

(with Prem Bahl) "Transmission Access Issues: Present and Future," October, 1991.

(with David Berry) Substitution of Photovoltaics for Line Extensions: Creating Consumer Choices. Arizona Corporation Commission, 1992.

(with Barbara Keene and Kim Clark) Report of the Task Force on the Feasibility of Implementing Sliding Scale Hookup Fees, December, 1992.

(with Mike Kuby) "The Hub and Network Design Problem With Stopovers and Feeders: The Case of Federal Express," Transportation Research A., Vol. 27A, 1993, pp. 1-12.

(with David Berry) Staff Guidelines on Photovoltaics Versus Line Extensions. Arizona Corporation Commission, January 28, 1993.

(with Ray Williamson, Robert Hammond, Frank Mancini, and James Arwood) The Solar Electric Option (Instead of Power Line Extension). A joint publication of the Arizona Corporation Commission and the Arizona Department of Commerce Energy Office, August, 1993.

(with David Berry, Kim Clark, Barbara Keene, Jesse Tsao, Ray Williamson, Randall Sable, Roni Washington, Wilfred Shand, and Prem Bahl) Staff Report on Resource Planning. (Docket No. U-0000-93-052) Arizona Corporation Commission, 1993.

Staff Report On Rural Local Calling Areas. (Docket No. E-1051-93-183) Arizona Corporation Commission, March, 1994.

(with David Berry, Kim Clark, Barbara Keene, Glenn Shippee, Julia Tsao, and Ray Williamson) Staff Report on Resource Planning. (Docket No. U-000-95-506) Arizona Corporation Commission, 1996.

(with Barbara Keene) "Customer Selection Issues," NRRI Quarterly Bulletin, Vol. 19, No. 1, Spring 1998, National Regulatory Research Institute.

Staff Report on Purchased Gas Adjustor Mechanisms, (Docket No. G-00000C-98-0568) Arizona Corporation Commission, October 19, 1998.

Staff Report on the Rolling Average PGA Mechanism, (Docket No. G-00000C-98-0568),Arizona Corporation Commission, September 6, 2000.

Staff Report on the Use of a Circuit-Breaker in Adjustor Mechanisms, Arizona Corporation Commission, September 3, 2003.

Staff Report on Southwest Gas Filing for Pre-Approval of Cost Recovery for Participation in the Kinder Morgan Silver Canyon Pipeline Project, (Docket No. G-01551A-04-0192), Arizona Corporation Commission, June 2, 2004.

Staff Report on Arizona Public Service Company Filing for Pre-Approval of Cost Recovery for Participation in the Kinder Morgan Silver Canyon Pipeline Project , (Docket No. E-01345A-04-0273), Arizona Corporation Commission, August 16, 2004.

Staff Report on Arizona Public Service Company Filing for Pre-Approval of Cost Recovery for Participation in the Transwestern Pipeline Phoenix Project , (Docket No. E-01345A-05-0895), Arizona Corporation Commission, March 2, 2006.

Staff Report on Southwest Gas Filing for Pre-Approval of Cost Recovery for Participation in the Transwestern Pipeline Phoenix Project, (Docket No. G-01551A-06-0107), Arizona Corporation Commission, May 16, 2006.

Staff Report on UNS Gas Filing for Pre-Approval of Cost Recovery for Participation in the Transwestern Pipeline Phoenix Project, (Docket No. G-04204A-06-0627), Arizona Corporation Commission, January 30, 2007.

Staff Review of UNS Electric 2008 Renewable Energy Standard Tariff and Implementation Plan, (Docket No. E-04204A-07-0593), Arizona Corporation Commission, March 25, 2008.

Staff Report on Semstream Arizona Propane, Payson Division Bankruptcy, Reorganization, and other issues, Arizona Corporation Commission, June 6, 2008.

Staff Review of UNS Electric 2009 Renewable Energy Standard Tariff and Implementation Plan, (Docket No. E-04204A-07-0593), Arizona Corporation Commission, November 26, 2008.

Staff Review of Tucson Electric Power 2009 Renewable Energy Standard Tariff and Implementation Plan, (Docket No. E-01933A-07-0594), Arizona Corporation Commission, November 26, 2008.

Staff Report for Arizona Water Company and Global Water Resources LLC's Consolidated Docket Addressing Numerous Requests for Extensions of Certificates of Convenience and Necessity for Water and Wastewater Service as Well as the Transfer of Assets, (Docket No. W01445A-06-0199, etc.), Arizona Corporation Commission, May 10, 2009.

Staff Review of UNS Electric 2010 Renewable Energy Standard Tariff and Implementation Plan, (Docket No. E-04204A-09-0347), Arizona Corporation Commission, January 5, 2010.

Staff Review of Tucson Electric Power 2010 Renewable Energy Standard Tariff and Implementation Plan, (Docket No. E-01933A-09-0340), Arizona Corporation Commission, January 5, 2010.

Staff Review of UNS Electric 2011 Renewable Energy Standard Tariff and Implementation Plan, (Docket No. E-04204A-10-0265), Arizona Corporation Commission, November 8, 2010.

Staff Review of Tucson Electric Power 2011 Renewable Energy Standard Tariff and Implementation Plan, (Docket No. E-01933A-10-0266), Arizona Corporation Commission, November 9, 2010.

Additional Training

1990	Seminars on Regulatory Economics
1993	PURTI course on Public Utilities and the Environment
1996	Center for Public Utilities Workshop on Gas Unbundling and Retail Competition

1997	NARUC 6th Annual Natural Gas Conference
1998	Local Distribution Company Restructuring and Retail Access and Competition Conference
1998	NARUC 7th Annual Natural Gas Conference
1999 – 2007, 2010	NARUC Summer Committee Meetings
2001	Center for Public Utilities Workshop on Risk Management in Gas Purchasing
2003-2008	NARUC Winter Committee Meetings
2004-2007	NARUC Annual Convention

Memberships

NARUC – Staff Subcommittee on Gas – member, 1998 - present
NARUC – Staff Subcommittee on Gas – Vice-Chair - 2002 - 2004
NARUC – Staff Subcommittee on Gas – Chair - 2005 - 2007
Michigan State Institute for Public Utilities – NARUC Advisory Committee – 2005-2007
NARUC – North American Energy Standards Board Advisory Council – 2006 - present
NARUC – DOE LNG Partnership – 2003 - present

Staff Gas Procurement Review of Southwest Gas Corporation for the May 2007 Through June 2010 Period

Southwest Gas Corporation's ("Southwest" or "Company") previous rate case, in Docket No. G-01551A-07-0504, included a review of Southwest's gas procurement practices for the period of September 2004 through April 2007. The procurement review was conducted by Energy Ventures Analysis, Inc. The gas procurement review in this case will analyze the period from May 2007 through the end of the rate case test year, June 2010.

Purchased Gas Adjustor

Natural gas commodity costs and interstate pipeline transportation costs incurred by Southwest to provide natural gas service to its customers are passed through to customers via the purchased gas adjustor mechanism ("PGA"). Southwest does not earn a profit on costs passed through the PGA. Southwest has had a purchased gas adjustor in place for a very long period of time. The banded 12-month rolling average cost PGA mechanism currently in place for Southwest was initially implemented in June 1999. In creating this new form of the PGA mechanism for Southwest and other Arizona local distribution companies ("LDCs"), the Commission sought to balance various, sometimes conflicting, goals, including sending a price signal as the price of natural gas changes, protecting ratepayers from sudden and dramatic shifts in the cost of gas they pay, and to allow the LDC to collect its natural gas costs in a relatively timely manner. Prior to that time, Southwest's PGA rate only adjusted when Southwest made a filing with the Commission to change the PGA rate. The rolling average PGA mechanism sets Southwest's gas cost per therm for its customers at a rate equal to the average total natural gas cost Southwest has experienced in the most recent previous 12 months. Thus, the monthly PGA rate changes every month, but the changes from month to month tend to be very incremental in nature, barring large price swings or other unforeseen events.

The PGA rate is subject to a band, which limits how much movement the PGA can experience in a 12-month period. Southwest's band was initially \$0.07 per therm. In Decision No. 62994 (November 3, 2000), the Commission expanded the PGA bandwidth for Arizona LDCs, including Southwest to \$0.10 per therm. Further expansions have taken place in recent times by the Commission to \$0.13 per therm in Decision No. 68487 (February 23, 2006), and most recently in Decision No. 70665 (December 24, 2008) to \$0.15 per therm.

System Summary

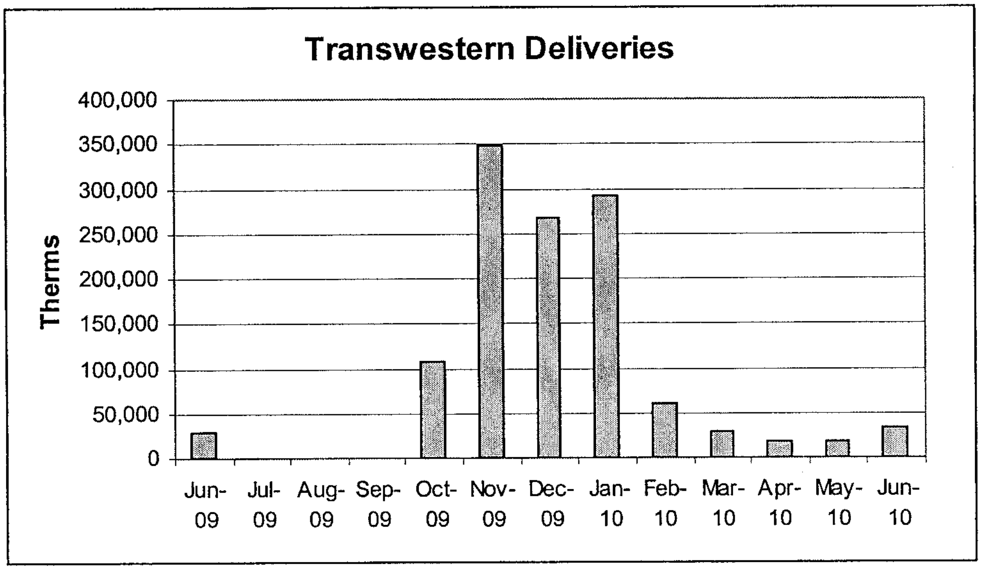
As of December 2010, Southwest serves approximately 977,500 customers in Arizona, including approximately 937,560 residential customers, 39,360 commercial customers, and 220 industrial customers. Southwest's service territory stretches across a wide swath of Arizona, from Cochise County in southeastern Arizona to La Paz County in western Arizona, including all of the Tucson metro area and most of the Phoenix metro area. Southwest also serves a small area around Bullhead City. Southwest's retail sales in Arizona for 2010 were 524,328,720 therms. The total cost, including the natural gas commodity and interstate transportation costs for 2010 was \$355,476,672. Due to lower natural gas prices, the total cost in 2010 was significantly lower than several recent years where Southwest's annual total cost was well in excess of $500,000,000.

Southwest acquires most of the natural gas to serve its customers from the San Juan supply basin in northwestern New Mexico and the Permian supply basin in west Texas. Southwest purchases natural gas supplies from suppliers in the supply basins and contracts with El Paso Natural Gas Company ("El Paso") and Transwestern Pipeline ("Transwestern") for pipeline capacity to deliver its natural gas supplies through their interstate pipeline systems to its service territory in Arizona. Southwest's Arizona distribution system has 208 meters and 123 active small taps on El Paso's system and 5 meters and 1 small tap on the Transwestern system. A meter is generally an interconnection point with service greater than 10,000 therms/day and uses telemetry. A small tap is generally an interconnection point with deliveries less than 10,000 therm/day and where measurement is done monthly. For scheduling on the El Paso system, Southwest is allowed to aggregate certain delivery points together for scheduling purposes, resulting in Southwest having 26 such d-codes in Arizona.

The Commission has had an on-going concern for many years regarding the monopoly on interstate pipeline service that El Paso held in most of Arizona, including central and southern Arizona, reflected in the Commission's involvement in many El Paso dockets at the Federal Energy Regulatory Commission ("FERC") for over a decade. Other shippers on the El Paso system, including large California shippers, have greater supply options and have been able to negotiate significant discounts for their service on the El Paso pipeline system, the costs of which are then borne by other shippers on the system who are unable to negotiate such discounts. This is a growing problem on the El Paso system, with several parties in El Paso's current rate case before FERC (FERC Docket No. RP10-1398) referring to the growing problems of capacity discounting and unsubscribed capacity as leading to a possible "death spiral" on the El Paso system. Both Southwest and the Commission are actively participating in El Paso's current rate proceeding before FERC, as well as other related dockets at FERC.

Transwestern's Phoenix Expansion represents some level of opportunity to diversify service options in central Arizona, although this is the case much more for electric generation facilities than for Southwest. Southwest does hold capacity on the Phoenix Expansion and takes service at a handful of points in the Phoenix area, but the Company is still largely captive to El Paso, given Southwest's many delivery points that are not near the Transwestern pipeline system. Southwest's participation, in the form of purchasing pipeline capacity, in the Phoenix Expansion was pre-approved by the Commission in Decision No. 68753 (June 5, 2006).

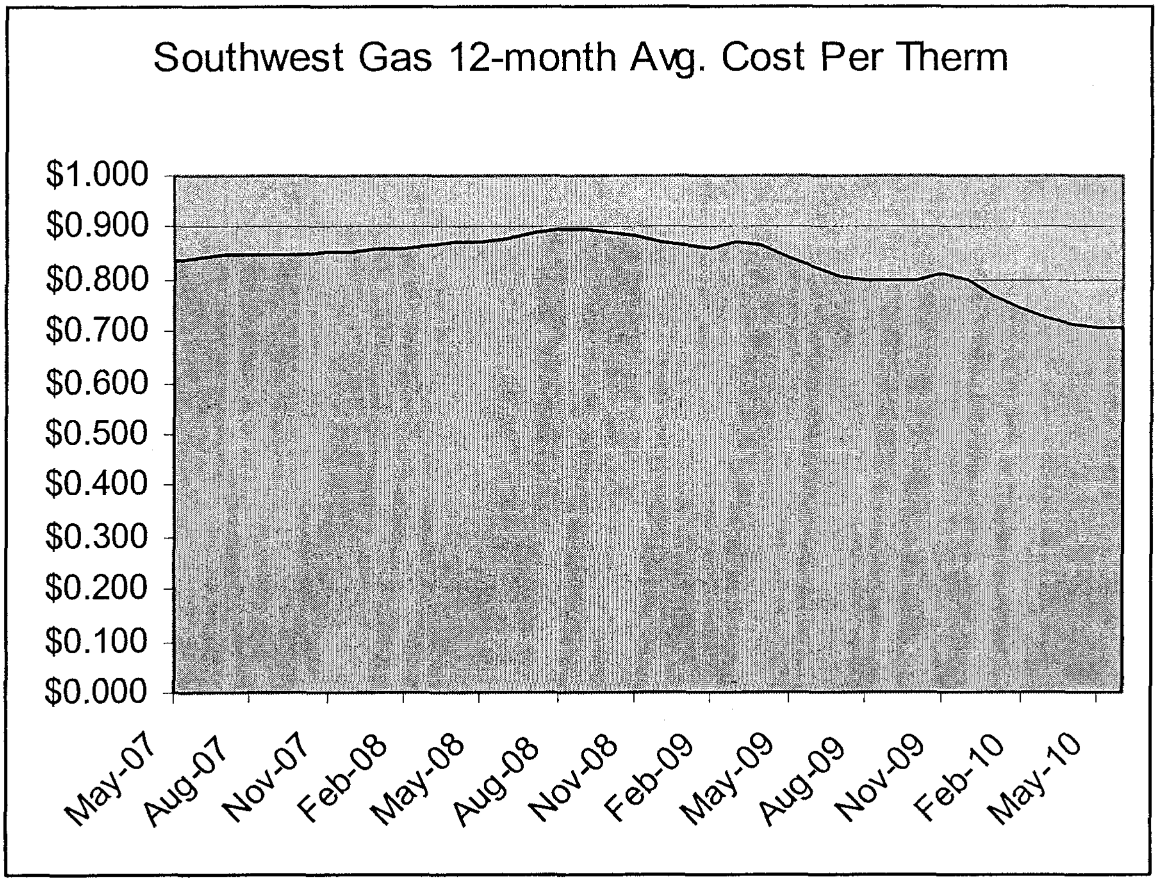
Southwest began receiving volumes in the Phoenix area from Transwestern's Phoenix Expansion beginning in June 2009. The graph below shows the volumes Southwest has received from Transwestern during the review period.



Review period

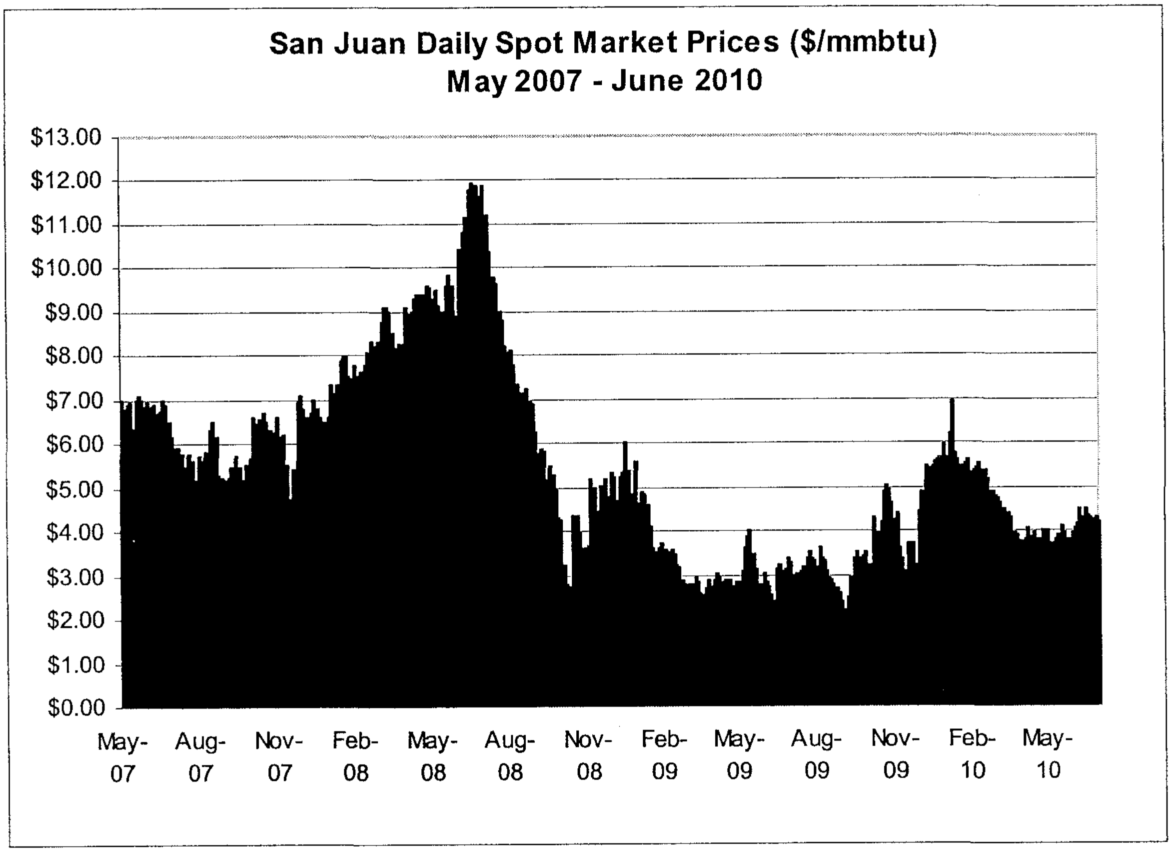
During the review period, Southwest's customer base showed moderate growth. In May 2007, Southwest had 963,101 total customers, compared to June 2010, where the Company had 978,512 customers.

The graph below shows the rolling 12-month average cost of natural gas for Southwest, including both the commodity cost and the interstate pipeline transportation cost. Cost per therm peaked in August and September 2008 at $0.895 per therm, with the lowest level being June 2010 at $0.707 per therm.



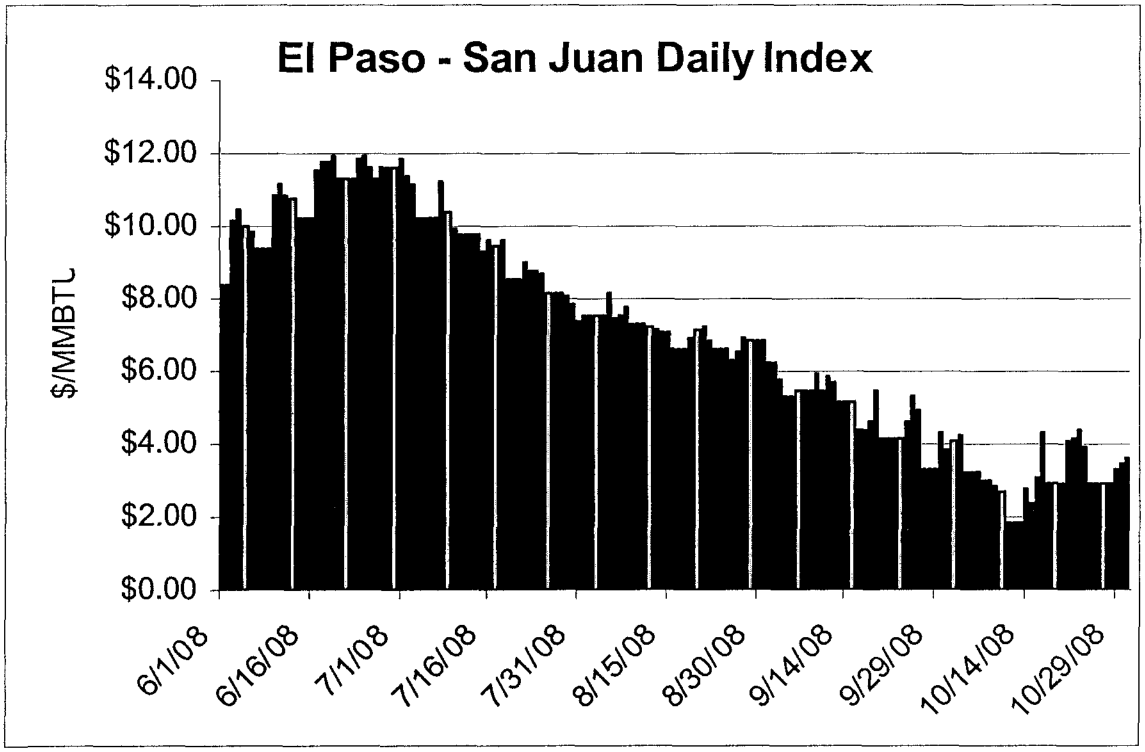
Market Conditions During the Review Period

The review period in broad terms had high and volatile prices early on, followed by much lower prices for the remainder of the review period due predominantly to prolific shale gas production. In contrast to the above graph showing Southwest's 12-month rolling average gas cost, the daily spot market price in the San Juan Basin during the same May 2007 through June 2010 timeframe was much more volatile, as shown in the chart below.



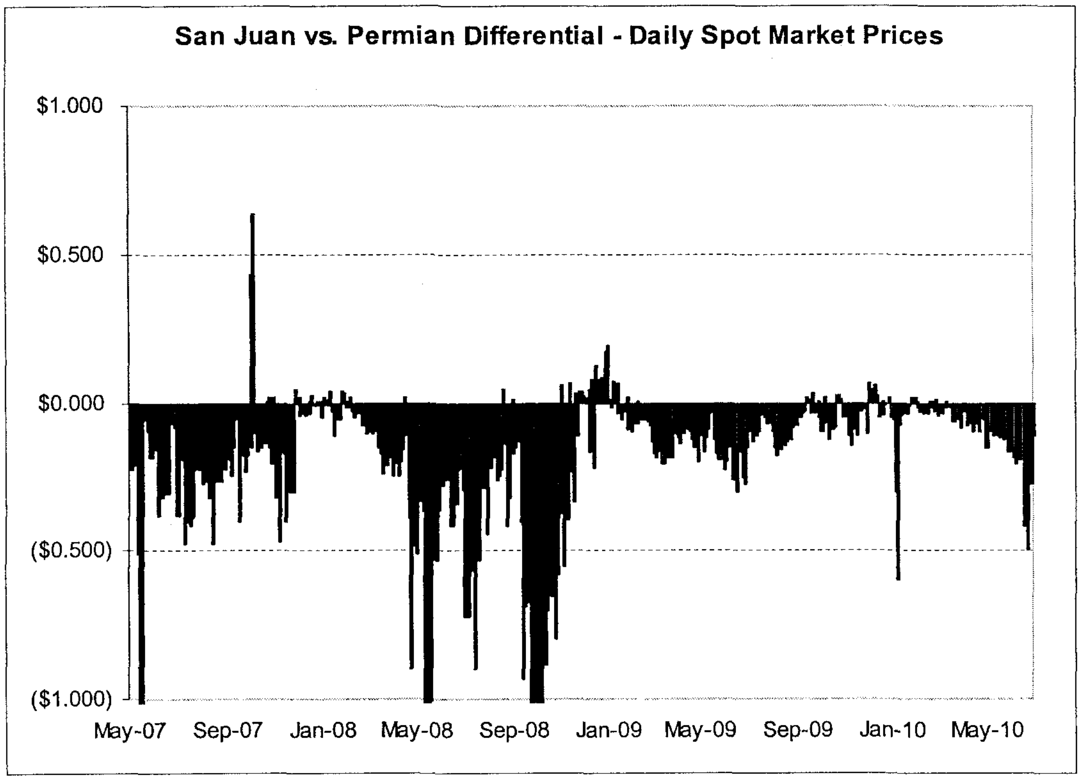
Source: Gas Daily

During the first year of the review period, natural gas prices were high, reaching well above $10.00 per MMBTU during the summer of 2008. During the summer of 2008, natural gas prices tumbled dramatically. The graph below shows the movement of prices during that summer.



Nationally, the explosive growth of shale gas was a primary driver in the lower natural gas prices the United States has experienced since the summer of 2008. The United States Energy Information Administration notes in its 2011 Annual Outlook that from 2006 to 2010, shale gas production increased at an annual average of 48 percent (page 2 of Executive Summary). During the review time period, pricing differentials between various natural gas pricing points declined around the country, due to a number of factors, including shale field development and construction of the Rockies Express pipeline by Kinder Morgan.

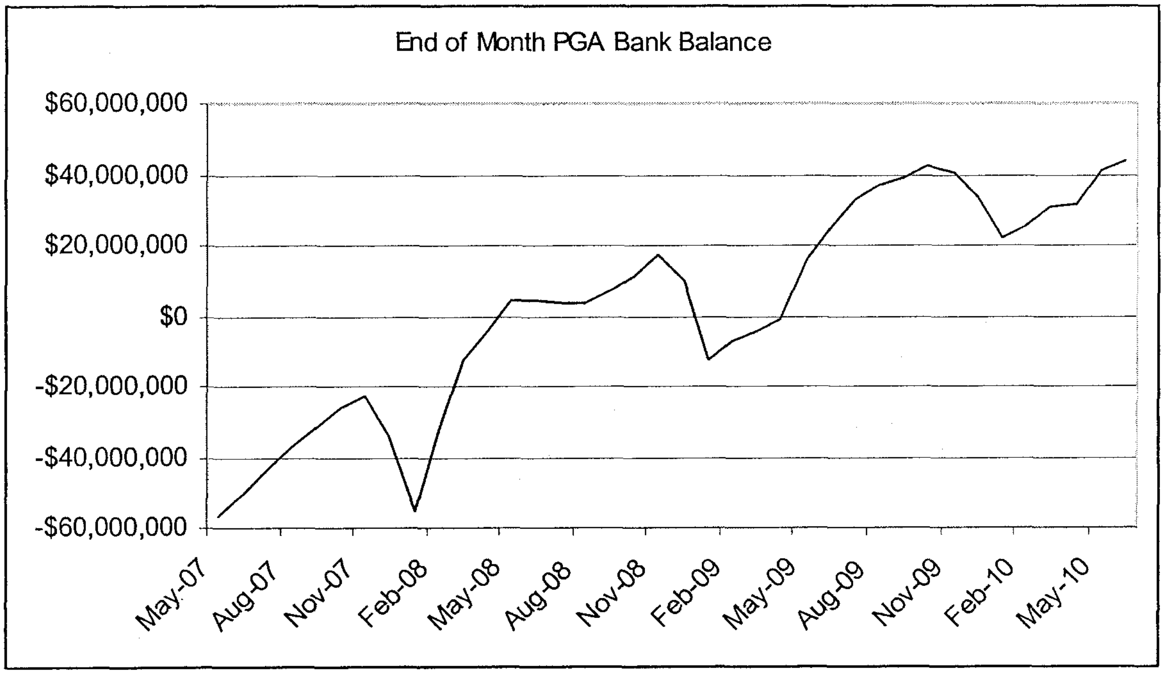
The San Juan and Permian supply basins are the two basins where Southwest gets virtually all of its natural gas supplies for its Arizona customers. Traditionally supplies from San Juan are cheaper than supplies from Permian, although this is not always the case, so Southwest and other Arizona entities typically try to source gas first from the San Juan basin, and secondly from the Permian basin. The graph below shows the differential between San Juan and Permian prices during the review period. A negative number means that the San Juan spot market price is lower than the Permian spot market price. A positive number means the Permian spot market price is lower than the San Juan spot market price.



Source: Gas Daily

The San Juan and Permian basins are not major shale production areas, but the growth in shale gas production had a dampening effect on natural gas prices across the country, including in the San Juan and Permian basins.

The chart below shows the end of month PGA bank balance for Southwest during the review period.



Note: A positive number reflects an over-collected PGA bank balance. A negative number reflects an under-collected PGA bank balance.

Review of Monthly PGA Reporting During Review Period

As part of this procurement review, Southwest's PGA reporting, contained in its monthly PGA report provided to the Commission, was reviewed. The monthly PGA report includes a monthly accounting for the PGA bank balance, consisting of the beginning of month PGA bank balance, inputs that increase and reduce the balance, and the end of month PGA bank balance. Other parts of the monthly PGA report include cost of gas details (commodity and interstate pipeline transportation costs), pipeline penalty charges incurred, calculations used in determining the next month's PGA rate, sales and customer numbers, average usage levels for residential customers, and an affidavit in support of the purchased gas adjustor report. Staff reviews the monthly PGA reports on an on-going basis, and consults with the Company if there are any anomalies or other issues with the report and works with the Company to resolve any outstanding issues. Thus, the review of monthly PGA reporting in this procurement review entails an overview of the on-going review Staff does. Staff does not have any outstanding issues with Southwest's monthly PGA reporting during the review period.

Core Customer Purchase Review

As part of the procurement review, Staff selected three random months to review the purchases made by Southwest as a spot check of their purchasing activities during the review period. Specifically, Staff reviewed Southwest's purchases during April 2008, August 2009, and January 2010. Staff compared the prices paid by Southwest to pricing information available in the Gas Daily publication, including daily and monthly indices and futures contract prices. Staff also considered market conditions prevalent at the time contracts were entered into and Southwest's efforts to reduce price volatility as one of its supply portfolio goals.

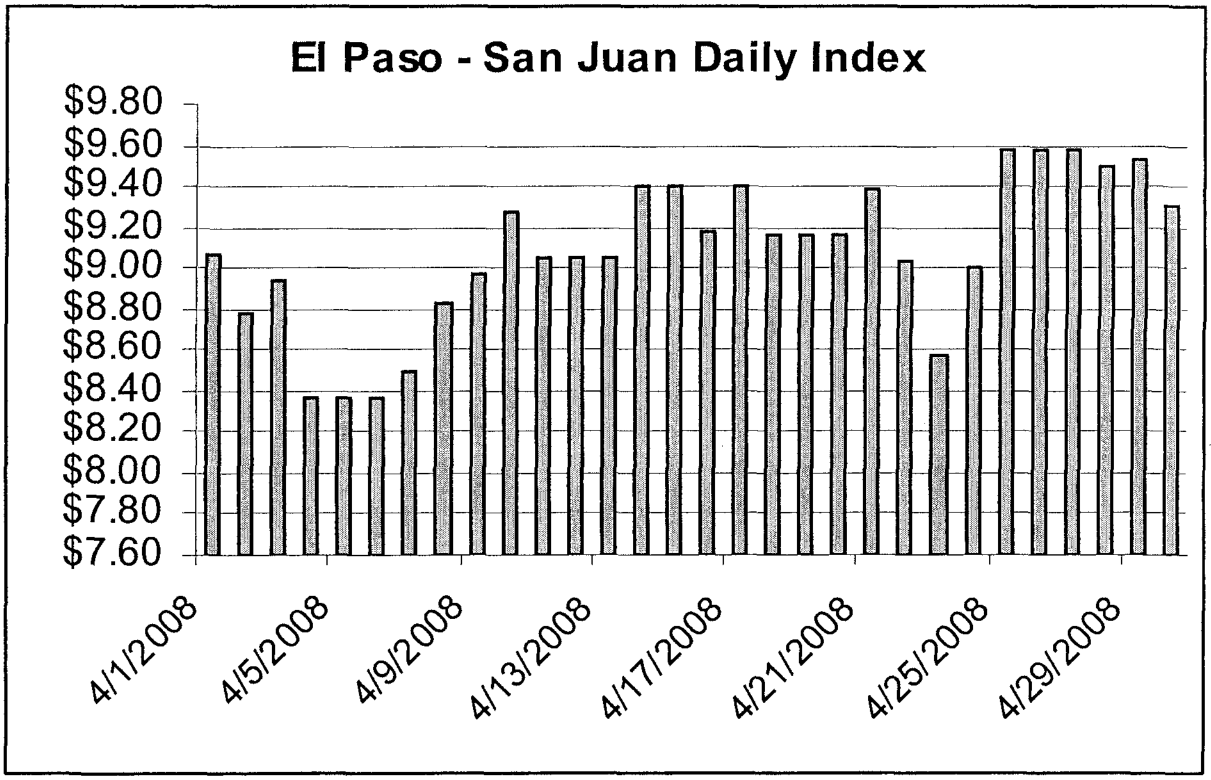
April 2008 Gas Purchases

In April 2008, Southwest had one seven-month fixed price contract in place as well as four one-year contracts in place with a total daily volume of 42,500 decatherms. These contracts were with four different suppliers and they were all sourced at either the Bondad Station or Blanco receipt points in the San Juan supply basin. The term of the seven-month contract was from April 2008 through October 2008. The term of the four one-year contracts was from November 2007 through October 2008. The contracts were entered into between January 1, 2007 and August 9, 2007.

The rest of Southwest's purchases in April 2008 were short term spot purchases, ranging from one to thirty days in length. These short term purchases were from 22 different suppliers. The receipt points involved in these purchases are Bondad Station and Blanco in the San Juan supply basin and Keystone and Waha-El Paso in the Permian supply basin. The vast majority of the short term deals were at a fixed price, with a small minority tied to indices published by the Gas Daily and Inside FERC publications. The table below details the contract lengths and daily volumes involved in the spot short term purchases.

Length of Contract	Number of Contracts	Total Daily Volumes (decatherms)
One Day	114	997,503
Two Days	1	4,200
Three Days	27	258,146
Four Days	2	20,000
Thirty Days	6	16,300

The graph below shows natural gas spot prices during April 2008 at the El Paso – San Juan pricing point, highlighting the high and volatile prices that were occurring during that time period.



Source: Gas Daily

Staff has reviewed the short term and longer term gas supply contracts in place during April 2008 and believes that the prices paid under them are reasonable given prevailing market prices and conditions.

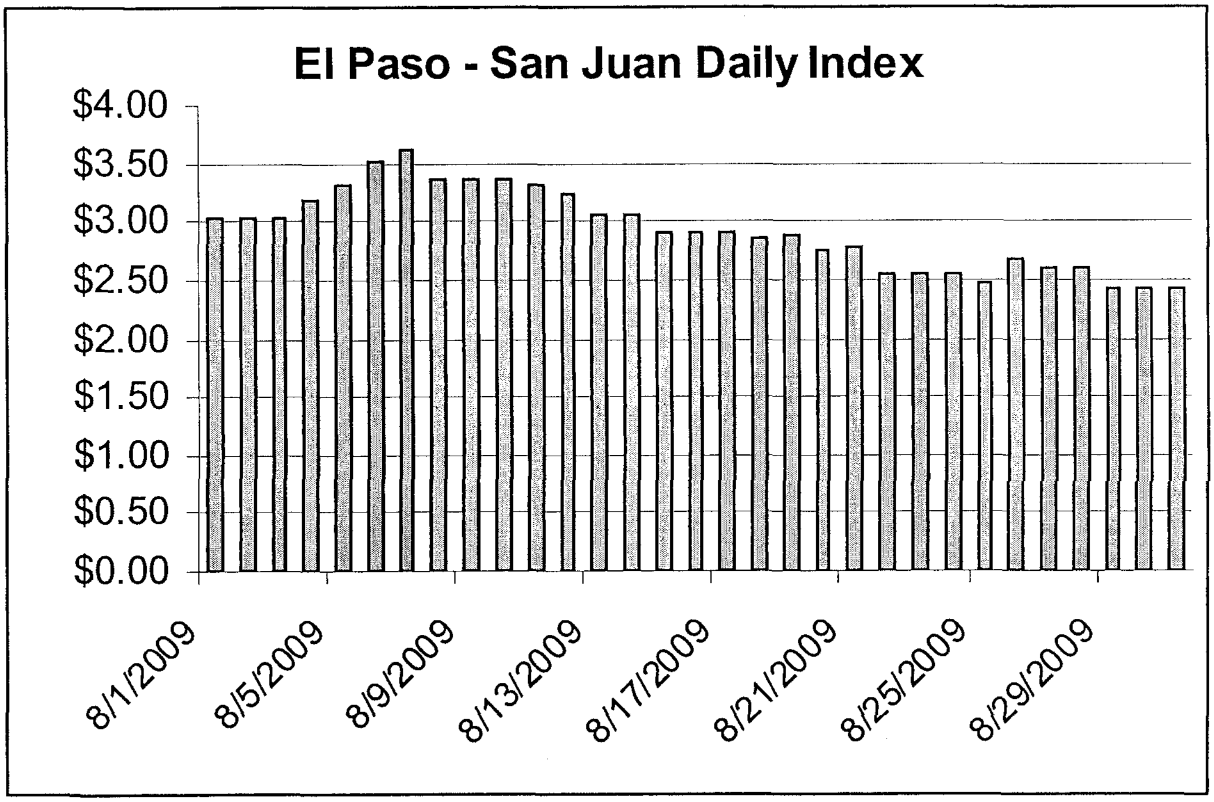
August 2009 Gas Purchases

In August 2009, Southwest had four seven-month fixed price contracts in place with a total daily volume of 35,000 decatherms. These contracts were with two different suppliers and they were all sourced at the Bondad Station in the San Juan supply basin. The term of all four contracts was from April 2009 through October 2009. The contracts were entered into between April 10, 2008 and August 13, 2008.

The rest of Southwest's purchases in August 2009 were short term spot purchases, ranging from one to thirty-one days in length. These short term purchases were from 18 different suppliers. The receipt points involved in these purchases are Bondad Station, Blanco, and TransColorado to Blanco in the San Juan supply basin and Keystone in the Permian supply basin. The vast majority of the short term deals were at an index price published in the Gas Daily and Inside FERC publications, with a minority having a fixed price. The table below details the contract lengths and daily volumes involved in the spot short term purchases.

Length of Contract	Number of Contracts	Total Daily Volumes (decatherms)
One Day	26	130,100
Three Days	15	51,300
Six Days	10	60,000
Seven Days	12	100,000
Thirty-One Days	39	32,900

The graph below shows natural gas spot prices during August 2009 at the El Paso – San Juan pricing point, highlighting the dramatic decline in prices that had taken place since mid 2008.



Source: Gas Daily

Staff has reviewed the short term and longer term gas supply contracts in place during August 2009 and believes that the prices paid under them are reasonable given prevailing market prices and conditions.

January 2010 Gas Purchases

In January 2010, Southwest had forty-five fixed price contracts in place with lengths ranging from one to twelve months. The table below details the contract lengths and volumes for the longer term contracts.

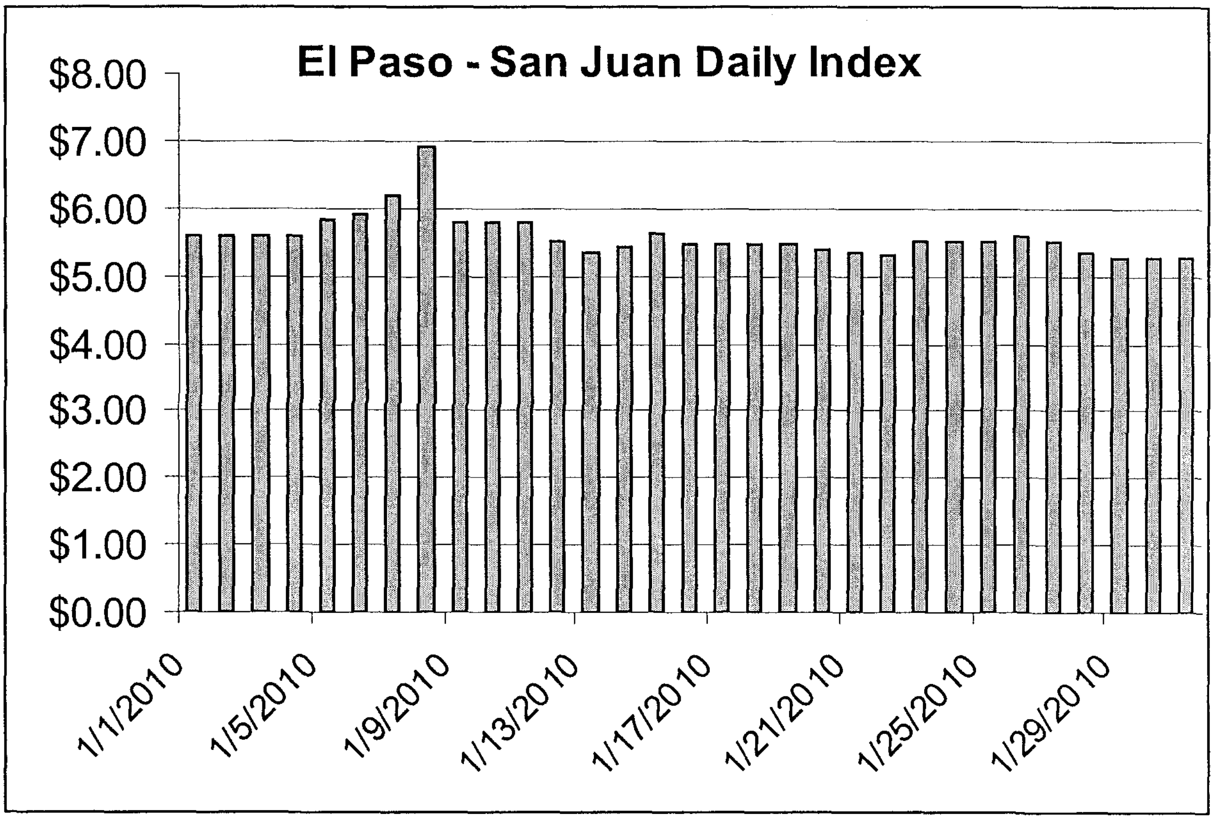
Length of Contract	Number of Contracts	Total Daily Volumes (decatherms)
One Month	4	98,868
Two Months	2	31,690
Three Months	3	55,000
Four Months	3	62,377
Five Months	30	635,871
Twelve Months	3	90,000

These contracts were with eleven different suppliers and they were sourced at the Bondad Station, Blanco, and Transwestern-San Juan receipt points in the San Juan supply basin and the Keystone and Waha-El Paso . The terms of the contracts have starting dates from November 2009 to January 2010 and ending dates from January 2010 to October 2010. The contracts were entered into between December 13, 2007 and October 8, 2009.

The rest of Southwest's purchases in January 2010 were short term spot purchases, ranging from one to thirty-one days in length. These short term purchases were from ten different suppliers. The receipt points involved in these purchases are Blanco, and Transwestern-San Juan in the San Juan supply basin, Keystone in the Permian supply basin, and one purchase from Plains in the Anadarko supply basin. The vast majority of the short term deals were at an index price published in the Gas Daily and Inside FERC publications, with a few having a fixed price. The table below details the contract lengths and daily volumes involved in the spot short term purchases.

Length of Contract	Number of Contracts	Total Daily Volumes (decatherms)
One Day	17	15,893
Three Days	4	22,700
Four Days	4	12,100
Thirty-One Days	4	19,864

The graph below shows natural gas spot prices during January 2010 at the El Paso – San Juan pricing point, highlighting the continued relatively low prices for natural gas during that time period.



Source: Gas Daily

Staff has reviewed the short term and longer term gas supply contracts in place during January 2010 and believes that the prices paid under them are reasonable given prevailing market prices and conditions.

Use of Financial Instruments

During the review period, Southwest utilized one form of financial instrument as part of its natural gas supply portfolio, entering into a number of fixed/float swaps during that time. Southwest has indicated that it continues to review the potential for using other forms of financial instruments, but the Company does not believe that any other form of financial instrument would be beneficial to use within its gas supply portfolio at this time. When Southwest is acquiring its natural gas supply portfolio, fixed/float swaps compete directly with traditional contracts for physical gas delivery.

A fixed/float swap financial instrument is a transaction where Southwest enters into a fixed price financial arrangement with a counterparty for a given volume of natural gas over a period of time. For example, Southwest entered into a fixed/float swap with Key Bank National Association ("Key Bank") on December 17, 2008, for a five month term of November 1, 2009 through March 31, 2010. The fixed price was $6.12 per million british thermal units ("MMBTUs") for a monthly volume ranging from 420,000 to 465,000 MMBTUs per month.

The Index Point referenced in the swap was the El Paso San Juan Gas Daily first of month index. So each month, the fixed price of $6.12 was compared to the first of the month El Paso San Juan index. If the index is higher than the fixed price, the counter party pays Southwest the difference. If the index is lower than the fixed price, Southwest pays the counterparty the difference. For the Key Bank swap, the first of month indices for the five months varied from $4.26 to $5.72 per MMBTU, resulting in Southwest paying Key Bank approximately $2.9 million over the term of the swap. Separately, Southwest actually procures physical supplies to meet its customers' natural gas requirements, given that the swaps are only financial transactions.

During the review period, Southwest entered into float/fixed swap transactions with Key Bank, JP Morgan Ventures Energy Corp, and Credit Suisse Energy. The table below summarizes these transactions.

Counterparty	Trade Date	Swap Term	Volume over Term (MMBTU)	Fixed Price ($/MMBTU)	El Paso – San Juan Index Range ($/MMBTU)	Profit/Loss of Fixed/Float Swap
JP Morgan	4/10/2008	12/08 - 2/09	1,800,000	$9.97	$3.11 to $4.83	-$10,339,200
JP Morgan	2/12/2009	4/10 – 10/10	2,140,000	$5.41	$3.22 to $4.28	-$3,492,600
Key Bank	12/17/2008	11/09 – 3/10	2.265,000	$6.12	$4.26 to $5.72	-$2,902,800
Credit Suisse	4/17/2009	12/09 – 1/10	930,000	$4.84	$4.28 to $5.72	$153,450
Credit Suisse	5/21/2009	12/09 – 3/10	1,210,000	$5.11	$4.28 to $5.72	-$149,050
Credit Suisse	6/11/2009	4/10 – 10/10	1,830,000	$5.48	$3.22 to $4.28	-$3,653,100

In total, Southwest's swaps during the review period involved a total volume of 10,175,000 MMBTUs, a relatively small portion of Southwest's overall gas purchases during that time period. The sum loss or payment to the counterparties during the review period was $20,383,300. This is a significant amount, with by far roughly half of the loss involving the three month swap with JP Morgan in late 2008 and early 2009. However, this loss should be considered within the broader context of Southwest's hedging efforts and the natural gas market conditions that existed during the review period. The fundamental purpose of hedging is not to achieve the lowest price, but rather to reduce volatility in the purchase of natural gas by Southwest, thus reducing the volatility Southwest's customers experience as natural gas costs are passed through by Southwest to its customers. The Commission has recognized the value of hedging natural gas prices over the years, including the decision that created the current PGA mechanism, Decision No. 61225 (October 30, 1998), which stated that "The Commission recognizes price stability as one of the goals of the natural gas procurement process." (page 2, Finding of Fact No. 9)

During the early to mid 2000s, as natural gas prices generally trended upward, Southwest's hedging efforts not only resulted in less volatile prices, but also saved ratepayers many millions of dollars in natural gas costs. In Staff's procurement review in Southwest's 2004-2005 rate case (Docket No. G-01551A-04-0876), Staff noted the following regarding Southwest's fixed price physical purchases at that time:

> "Over time it is to be expected that such fixed price contracts will at times end up being higher priced than actual market prices and at times end up being lower prices that actual spot market prices. In recent years natural gas prices have

> generally been increasing. In such an environment, prices which have been locked in for a period of time generally result in lower than market prices over the term of the contract. Therefore Southwest's longer term, fixed price purchases in recent years have generally saved money over a situation where Southwest had bought all of its supplies based upon spot market indices. This has been a beneficial side effect of the longer term, fixed price contracts, but it should be recognized that at points where natural gas market prices may be in decline that such purchases will result in higher than spot market prices, tying back to the recognized goal of such contracts of introducing a measure of price stability." (Gray Direct Testimony, pages 29-30)

In contrast, recent years, including the review period, has been a period of generally declining natural gas prices. In such a market, hedging efforts will likely result in higher overall prices, but such a result is not necessarily a problem. These two time periods demonstrate that over time hedging will at times save money for customers, but will at other times cost more money for customers via changes in the PGA rate over time. Southwest currently has seven approved counterparties which it may enter into swaps with.

Specifically in looking at the swaps during the current review period, the April 2008 JP Morgan swap was entered into at a time when natural gas prices were quite high and trending upward, reaching a peak shortly thereafter on June 20, 2008 of $11.94 per MMBTU for the El Paso – San Juan index. Subsequently natural gas prices dropped precipitously, resulting in the JP Morgan swap appearing to be very expensive and resulting in a significant payment from Southwest to JP Morgan, but if prices had stayed at the June 2008 high or gone even higher, the JP Morgan swap would have saved Southwest and its customers a significant amount. On the day the JP Morgan swap was entered, April 10, 2008, the New York Mercantile Exchange natural gas futures for December 2008, January 2009, and February 2009 were $11.075, $11.30, and $11.265 per MMBTU. The NYMEX futures contract is based upon Henry Hub pricing, which typically trades at a premium to San Juan basin prices. But the premium is typically a dollar or less. Thus, the $9.97 price for the JP Morgan swap seems reasonable given market conditions. Further, it is worth noting that, while the JP Morgan swap resulted in a significant payment from Southwest, the net result is little or no different than if Southwest had directly contracted for natural gas supplies in April 2008 for the December 2008 – February 2009 time period. The loss just would have been built into the high cost of the directly contracted gas, rather than as a payment to the swap counterparty.

From the information available at this time, Staff believes that Southwest's use of swaps is a reasonable way for Southwest to diversify its hedging efforts and that it is reasonable for the direct costs of the swaps to be recovered by Southwest through its PGA mechanism.

Because use of such swaps by Southwest is a relatively recent phenomenon, Southwest's traditional reporting of information to the Commission does not always include detailed information regarding the swaps. Specifically, Southwest's Annual Gas Procurement Plan it files with the Commission does not contain a detailed discussion, explanation, and documentation of Southwest's use of financial instruments, and specifically its use of swaps in recent years. Therefore, Staff recommends that in all Annual Gas Procurement Plans filed by Southwest, there be a separate section of the report providing a detailed explanation and documentation of the use of financial instruments by Southwest, and specifically at this time the swaps used by Southwest.

CNG Purchases

Between April 2008 and April 2009, Southwest provided compressed natural gas ("CNG") service to the Tartesso Subdivision ("Tartesso") in Buckeye, Arizona. Provision of CNG service is much more expensive than normal natural gas service through Southwest's distribution system. The reason for Southwest's provision of CNG service to Tartesso is that Tartesso was planned to be served off of Transwestern Pipeline's Phoenix Expansion project, a new pipeline that was built to, among other reasons, provide an alternative for interstate pipeline service in central Arizona. Tartesso was not located near Southwest's existing distribution system in the Phoenix area, and delays in construction of the Phoenix Expansion resulted in customers needing natural gas service in Tartesso, but having no way of having natural gas delivered through Southwest's existing distribution system or off of the Phoenix Expansion. The Phoenix Expansion was originally scheduled to go into service in May 2008, but due to siting difficulties and other delays, did not begin operations until March 2009. During that period, Southwest used CNG to serve the customers in Tartesso until such time as gas could be delivered to them off of the Phoenix Expansion. Natural gas was provided to Tartesso during this period by Southwest having natural gas delivered to an existing point on its Phoenix distribution system, and hiring a contractor to compress it and deliver it to Southwest's distribution line in Tartesso. Southwest spent a total of $3,160,638 for compression and transportation services to Rawhide Leasing Company, in addition to Southwest's cost of the natural gas commodity to serve Tartesso. Southwest delivered an estimated 159,520 therms to Tartesso during that period.

The delays in the in-service date for Transwestern's Phoenix Expansion were beyond Southwest's ability to control, and thus Staff believes that Southwest's steps to use CNG for a temporary period, while very expensive in comparison to normal natural gas service, was necessary to provide service to new customers within its certificated service territory in Tartesso. Southwest's only documentation that was provided to the Commission during this period was a line item on the monthly PGA reports that indicated the cost of CNG services each month such costs were incurred. Staff believes that it would be beneficial for Southwest to, in the future, provide an explanation in its monthly PGA reports anytime in the future it uses CNG supplies to provide service within its service territory. Specifically, Staff recommends that Southwest provide an explanation in any future PGA report when it begins to recover CNG costs for serving a given area through the PGA mechanism, indicating the reason(s) for such service, expected length such service will be necessary, and estimated cost and volume of such service.

Comparison of SPA purchases vs. Core Purchases

Southwest purchases natural gas both for its core customers and its special gas procurement agreement ("SPA") customers, who sign separate contracts with Southwest under Schedule G-30, Optional Gas Service. Schedule G-30 is available to customers who can demonstrate one or more of the following criteria:

1. Customers whose average monthly requirements on an annual basis are greater than 11,000 therms per month and who have installed facilities capable of burning alternate fuels or energy.
2. Customers whose average monthly requirements on an annual basis are greater than11,000 therms per month and who can demonstrate to the Utility sufficient evidence of economic hardship under the customer's otherwise applicable sales tariff schedule.
3. Customers whose requirements may be served by other natural gas suppliers at rates lower than the customer's otherwise applicable gas sales tariff schedule. As a condition precedent to qualifying for service under this applicability provision, the customer must qualify for transportation service under Schedule No. T-1 and establish that bypass is economically, operationally and physically feasible and imminent.

Typically in the past the threat of bypass, in the form of taking service directly from a nearby interstate pipeline, has been the main reason why customers have been able to take service under Schedule G-30. Southwest assesses the viability of the threat of bypass, and if it believes the threat is real, it negotiates a SPA with the customer, typically offering a discount off of what the customer would pay under its other applicable tariff(s), but receiving some level of contribution from the customer to help pay for system costs. Southwest then is required to file the SPA with the Commission for approval. Under SPAs, Southwest acquires natural gas supplies for the SPA customer.

In the past the Commission has taken an interest in the prices paid by a utility for natural gas commodity purchases for both core and noncore customers, to ensure that core customer purchases do not suffer as a result of Southwest's efforts to procure the best supplies for its noncore customers. A primary way of comparing a local distribution company's ("LDC") purchases for core and noncore customers is to compare purchases that are similar in nature that were made during the same period of time for core and noncore customers. Staff held a number of discussions with Southwest regarding its purchases for SPA customers and reviewed data provided by Southwest regarding SPA purchases. Information provided by Southwest indicates that during the period of this review, there were periods of time when there were comparable purchases made for both core and noncore customers. Thus, Staff has no reason to believe there are any potential, let alone actual, conflicts of interest between core and noncore purchases.

Summary

In summary, Staff finds that Southwest's procurement activities during the review period of May 2007 through June 2010 are prudent. Staff further makes the following recommendations to update the information provided by Southwest to the Commission regarding its gas procurement and PGA activities:

1. Staff recommends that in all Annual Gas Procurement Plans filed by Southwest, there be a separate section of the report providing a detailed explanation and documentation of the use of financial instruments by Southwest, and specifically at this time the swaps used by Southwest.
2. Staff recommends that Southwest provide an explanation in any future PGA report when it begins to recover CNG costs for serving a given area through the PGA mechanism, indicating the reason(s) for such service, expected length of time such service will be necessary, and estimated cost and volume of such service.

Section of May 22, 2008 Staff Report on Semstream Propane Arizona

7. What other alternatives exist for utility service to Payson? UNS Gas, Southwest Gas, and other options.

Given the very high price of propane and the likelihood that propane will remain an expensive fuel for home heating and other uses, one matter for possible consideration is whether some other utility service option would be possible for Payson. With natural gas prices current roughly half of what propane costs, extension of natural gas service to Payson by one of Arizona's natural gas local distribution companies is one potential option to provide some relief to propane users in Payson.

Semstream indicated that at the time Great Falls Gas Company purchased the Payson Division from Broken Bow, that Great Falls considered the possibility of extending natural gas service to Payson. Semstream indicated that its understanding is that Great Falls found that the volume of sales available in Payson did not justify the cost of building the infrastructure necessary to bring natural gas to Payson. One complication was that the system would have needed to be run at a very high pressure, possibly 800 pounds per square inch ("psi"), due to the significant length of the line that would run to Payson from Camp Verde or another distant location. This pressure level is higher than most end users require, even for power plant operations. To provide this level of pressure would have led to additional costs. Another difficulty that was identified was that the Payson Division has a number of satellite systems serving small groupings of customers that are too distant from the underground system to economically interconnect. These satellite systems can be served with propane service via truck delivery with little difficulty, a delivery mechanism that would not work nearly as well for natural gas. If natural gas service were to reach Payson, it is not clear how customers of these satellite systems would continue to receive service from the Payson Division.

However, extension of natural gas service to Payson faces a number of significant obstacles. Staff has held high level discussions with UNS Gas and Southwest Gas, two natural gas utilities that could potentially extend service to Payson from their existing service territories.

UNS Gas indicated to Staff that its closest facilities to Payson are in Camp Verde. Extension of service to Payson would involve construction of a 54 mile pipeline, with an initial estimate from UNS Gas of a cost of approximately $60 million (roughly $170 to $200 per foot). This amount does not include any additional costs to tie into the local distribution system in the Payson area.

For Southwest Gas, its closest facilities are in Fountain Hills, resulting in a 53 mile pipeline extension if it were to extend service to Payson. Southwest indicated an initial cost estimate would be over $50 million. Southwest believes that if the costs of such an extension were paid specifically by customers in the Payson area, that rates in Payson would be significantly higher than Southwest's general Arizona tariffs. Southwest did indicate that rate treatment would be a significant issue in determining the economics of the project. If the costs of the extension were given rolled-in treatment, spreading them over all Southwest's customers, Southwest believes that such an increase for all Arizona customers would be a single-digit percentage increase.

If an effort were made to tie directly into the nearest interstate pipeline, this would be El Paso's Maricopa Lateral which roughly tracks the I-17 highway coming down from Flagstaff and is approximately 50 miles west of Payson. Southwest Gas indicated it believed an extension connecting directly to El Paso's system would cost upwards of $50 million.

Beyond the significant cost of extending a pipe to Payson, a number of other issues would need to be addressed. Any line would run through significant amounts of rugged territory such as national forest land and possible national wilderness land, raising possible environmental issues and construction challenges. For UNS, the entire route would traverse national forest land and possibly national wilderness land. There is an Arizona Public Service Company ("APS") transmission line that runs roughly from Camp Verde to Payson, so that route would be one possibility. Another possibility would be to try to have such a line follow the the 260 and 87 Highways at least for portions of the way to Payson. For Southwest Gas, there are several APS transmission lines running from the Cholla generating station through the Payson vicinity and down into the Phoenix area, providing one possible existing right-of-way to explore. Without further investigation, Staff does not know whether any space exists in the APS right-of-way. Another possibility would be for the route to run along Highway 87 from Fountain Hills to Payson. Other possible land issues for Southwest Gas could be the McDowell Mountain Regional Park and the For McDowell Indian Reservation, which skirt Fountain Hills on the north and east. Between the land status and the rugged geology to be crossed, finding a route for a natural gas line extension to Payson would be a challenging endeavor.

Another possible cost issue for a UNS Gas or Southwest Gas expansion would be whether their backbone pipeline systems, which currently deliver gas to Camp Verde and Fountain Hills, have spare capacity to serve the additional load Payson represents. The distribution lines serving Camp Verde and Fountain Hills are at the end of their respective distribution systems and may not have the spare capacity to also be able to handle throughput for potential new demand in Payson. Thus, it seems likely that some amount of additional facilities would need to be added so that the upstream distribution system would be able to handle the additional throughput to which an extension to Payson would lead.

If a way were found to extend a natural gas line to Payson, another issue to be addressed is that Semstream currently holds a Certificate of Convenience and Necessity to serve Payson and surrounding areas and owns the propane distribution system in the Payson area. Semstream paid approximately $15 million to acquire the Payson Division from Energy West in 2006. It is unclear how the extension of a natural gas distribution line by UNS Gas or Southwest Gas for natural gas service in Payson would be made compatible with Semstream's ownership of and investment in the Payson Division. Possibilities would include the acquisition of the Payson Division by UNS Gas or Southwest Gas, or some other arrangement between Semstream and the natural gas LDC.

On a general note, Staff has observed over time that major gas line extensions in Arizona are often the result of the natural gas demand by a large end user, who serves as a sort of "anchor tenant" to give critical mass to demand for the line extension. Staff is not aware of what, if any, large commercial or industrial entities may exist in the Payson area that could serve as an anchor tenant, but if such an end user were identified, it could significantly improve the economics of getting a natural gas pipeline built to Payson.

A historic experience of note is the major buildout program Citizens Utilities ("Citizens"), now UNS Gas, undertook in the 1990s to upgrade the distribution system and extend natural gas service to a number of new communities in northern Arizona. Citizens Utilities' buildout program was ordered as part of Citizens' acquisition of the Arizona natural gas distribution system assets of Southern Union Gas Company and reflect significant concerns at the time regarding the safety and maintenance of the Southern Union system. Citizens Utilities' buildout program has a long and complex history, with the program costing significantly more and taking significantly longer to build than was initially projected. The program provided for customers in communities where natural gas service was extended to, to pay a 50 percent bill adder for a number of years to contribute toward the costs of extending service. Given delays in construction, lower than expected penetration levels, and other factors, these new customers' contributions to the cost of the extensions was less than expected. In combination with higher than expected costs, Citizens' existing customer base ended up paying higher rates to help pay for the buildout program, resulting in some level of cross-subsidization between existing and new customers. Given the likely high cost of extending a natural gas pipeline to Payson, the Commission would need to carefully balance the various interests of both new customers in Payson and existing natural gas utility customers as it considers cost recovery, ratemaking treatment, and other issues.

Another possible option would be to truck liquid natural gas ("LNG) into Payson and the regasify it for distribution via the existing distribution system. As with any option bringing natural gas into Payson, there would likely be some costs to adjust the local distribution system to distribute natural gas rather than propane. However, the larger barrier to bringing LNG to Payson would be the significant investment in liquefaction and regasification facilities. The cost of such LNG would be noticeably higher than natural gas delivered through a normal pipeline system, but if the price differential between propane and natural gas was large enough over a sustained period, such a system could be a possibility.

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *

ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-12
(ACC-STF-12-1 to ACC-STF-12-18)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: APRIL 12, 2011

Request No. ACC-STF-12-18:

The Commission held town halls in southern Arizona on April 6 and 7, 2011 regarding the February 2011 service outages. At the town halls numerous members of the community expressed concern with Southwest's communications during the outages. Please provide a plan in response to this data request, identifying how Southwest will improve both how it communicates with its customers and what information is communicated with its customers regarding any future service outages in Arizona.

Respondent: Conservation and Demand Side Management

Response:

Southwest Gas Corporation (Southwest) has heard its customer's concerns related to the recent outage in Arizona. Customers asked that Southwest provide information that is timely, clear, pertinent, and easily accessible in the event of an emergency situation. Although Southwest's primary objective is to protect people and property, the Company understands the growing demand for enhanced communications and strives to meet the needs of its customers. Southwest has addressed customer concerns with communications during outages by supplying additional means of communication through social media, a map-based application, server redundancy, Reverse 911, and predictive dialing, as further described below. These solutions provide clear, pertinent, and timely information that is readily available and easily accessible.

One of the most frequently used, easily accessible means of communication is the internet. Southwest is incorporating several enhancements to web applications to improve customer communications. Southwest has also created Twitter and Facebook accounts in order to post timely updates in the event of an emergency. The Company's communications experts are developing the internal support needed to keep the information that is posted on these venues current and readily available.

Southwest understands that its customers would like visual representation of the outage and restoration areas. The Company's technology experts have developed an in-house Outage Mapping System (OMS) which is a map-based application used to illustrate the impacted area and the estimated number of affected customers. The application is easily accessed through the Southwest My Accounts web page. OMS provides an additional means of posting information and providing updates on outage restoration efforts. To increase the reliability of Southwest's web applications, Southwest will be utilizing additional servers in separate, off-site locations. Server redundancy will ensure the accessibility of the Company's web applications by utilizing the secondary server as needed.

For those customers who do not access the internet frequently, Southwest is incorporating additional methods of communication via telephone. Reverse 911 can be used to record an emergency message to distribute to the public through the local counties. Southwest understands that Reverse 911 has limitations including message duration, current phone listings, geographical area, and county availability. To better meet the needs of Southwest's customers, the Company is developing in-house predictive dialing which will contain specific contact information for its customers. This will allow customers to choose their preferred contact telephone number whether it be a cell, house, or work phone.

The Company's efforts to improve its communication with customers are on-going, and the Company will continue to provide enhancements with the advancement of technology.

BEFORE THE ARIZONA CORPORATION COMMISSION

GARY PIERCE
Chairman
BOB STUMP
Commissioner
SANDRA D. KENNEDY
Commissioner
PAUL NEWMAN
Commissioner
BRENDA BURNS
Commissioner

IN THE MATTER OF THE APPLICATION OF SOUTHWEST GAS CORPORATION FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS PROPERTIES THROUGHOUT ARIZONA	)	DOCKET NO. G-01551A-10-0458

DIRECT

TESTIMONY

OF

BRYAN FRYE

SENIOR PIPELINE SAFETY INSPECTOR

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JUNE 10, 2011

ALL-STATE LEGAL®
EXHIBIT
S-6

TABLE OF CONTENTS

ATTACHMENTS

EXECUTIVE SUMMARY
SOUTHWES GAS CORPORATION
DOCKET NO. G-01551A-10-0458

The Direct Testimony of Staff witness Bryan Frye addresses the following issues from the perspective of the Arizona Corporation Commission Office of Pipeline Safety:

1. Southwest Gas Corporation ("SWG") request to include the remaining money for the replacement cost of the Manors subdivision gas distribution system in Yuma, AZ,
2. A deferral account for a proposed two year pilot program to remove 5,000 Customer Owned Yard Lines ("COYL"),
3. A proposed Multiple Rate Customers plan, and
4. A deferral account for the replacement of Early Vintage Plastic Pipe ("EVPP").

Staff makes the following recommendations:

1. The remaining $225,445 from the Manors Subdivision replacement in SWG's most recent rate case should be disallowed from consideration in these proceedings and future rate case proceedings. SWG's original intention was to extend the service life of the pipeline system by installing new cathodic protections ground bed before incorrectly connecting the wires backwards on the rectifier causing the pipeline to corrode at an accelerated rate.
2. A deferral account for the two-year pilot program to replace 5,000 COYL should be disallowed because SWG has failed to provide any documentation regarding how or if this project would benefit the safety of the public.
3. SWG should use configuration number one or three in the attached diagrams in regard to the proposal for multiple rate customers.
4. SWG should continue with the replacement of EVPP and provide documentation of progress and money spent in these proceedings and in future rate cases.

INTRODUCTION

Q. Please state your name and business address?

A. My name is Scott Bryan Frye Jr. My business address is 2200 N. Central Avenue, Phoenix, Arizona.

Q. What is your current position and how long have you been employed by the Arizona Corporation Commission?

A. I am a Senior Pipeline Safety Inspector; I have been employed by the Arizona Corporation Commission ("Commission") for over 4 years.

Q. Please describe briefly your duties as a Senior Pipeline Safety Inspector.

A. Briefly, my duties include conducting annual pipeline safety inspections, conducting investigations into the causes of pipeline failures, conducting pipeline construction inspections, conducting inspections and/or investigations with respect to the Underground Facilities Law ("Blue Stake"), completing required reports associated with each inspection or investigation and providing testimony on behalf of the Commission.

Q. Please describe your education, training and pertinent work experience.

A. I have over 4 years experience as a Pipeline Safety Inspector with the Commission, where I have been sent to numerous Training and Qualifications classes in Oklahoma City that are conducted by The Department of Transportation Office of Pipeline and Hazardous Materials Safety Administration ("PHMSA"). Attached is a list of those specific classes. Prior to my time with the Commission I have over 10 years experience in the field of utility locating, design, and engineering. (See Attachment No. 1.)

Q. What is the purpose of your testimony in these proceedings?

A. The purpose of my testimony is to address the following issues from the perspective of the Commission's Office of Pipeline Safety ("Staff"):

1. The costs associated with the replacing of the distribution pipeline system in the Manors subdivision in Yuma, Arizona,
2. The two-year pilot program Southwest Gas Corporation ("SWG" or "Company") purposes for replacing Customer Owned Yard Lines ("COYL"),
3. The proposed multiple rate customer meter options, and
4. The proposed deferral account requested for the replacement of Early Vintage Plastic Pipe ("EVPP").

MANORS SUBDIVISION YUMA, ARIZONA

Q. Have you reviewed the information and documentation regarding the Manors replacement project in Yuma?

A. Yes, I have reviewed SWG's testimony in this case, the Direct Testimony of Corky Hanson (See Attachment No. 2) in Docket No. G-01551A-07-0504 (2008 rate case) and Decision No. 70665.

Q. Has Staff's position changed since the 2008 rate case with regards to allowing the remaining $225,445 in rate base as part of this case?

A. No, Staff's position has not changed on this matter. As Corky Hanson testified, the circumstances that necessitated the immediate replacement of this system were the direct result of incorrect actions taken by SWG personnel, resulting in the failure of the Manors' system.

Q. Explain the action taken by SWG personnel that caused the failure.

A. During the SWG annual code compliance audit in 2006, conducted by Staff, it was noted on the inspection report that SWG had not taken prompt remedial action to correct deficiencies of the Manors cathodic protection ("CP") identified during the annual CP monitoring done by SWG. The CP deficiency was identified on March 26, 2004. SWG did not complete remedial action until February 28, 2006. Failure to provide adequate and proper CP on a steel pipeline system can lead to deterioration of the pipeline resulting in leaks and ultimately the replacement of the pipeline. The technician responsible for making repairs to the CP rectifier system connected the wiring backwards (positive to negative / negative to positive); i.e., the wiring was improper. This action caused the pipeline to corrode at an accelerated rate resulting in multiple corrosion failures and necessitating the immediate and premature replacement of the steel pipeline system. SWG personnel did not identify this mistake until the system failed and required replacement.

Q. Based on your experience, could the Manors steel pipeline system have lasted for many more years if adequate CP had been properly applied?

A. Yes, based on my CP training and experience as a Pipeline Safety Inspector, this system could have lasted for many more years. Staff members Mr. Marion Garcia (Chemical Engineer) and Mr. Ryan Weight (Mechanical Engineer) were consulted on this issue as well. Both have extensive CP experience, and both agree with Mr. Hanson's and my assessment of this system. Pursuant to State and Federal regulations, SWG had the option to either replace the pipeline with plastic pipe (which does not require CP), or install CP.

Ground bed anodes on impressed current systems are normally designed to last a minimum of 20 years, when properly installed. When SWG made the decision to replace the ground bed anodes, instead of replacing the pipelines at the Manors, it was evident that the pipeline was in a condition that could be preserved (otherwise why replace the ground bed anodes). Clearly, the intent was to extend the service life of the Manors' system. One of the primary reasons for SWG to expend the cost and effort to replace the CP ground bed anodes to restore CP to the Manors' steel pipe system must have been to extend the service life of this system. Through only 11 months of operation using an incorrectly installed rectifier, the pipeline was corroded to the point of needing to be replaced sooner than otherwise would have been required. It is true that the pipeline had been in service for 50 years. However, as SWG's service life extension efforts demonstrate, there was no need at that time to replace the pipeline. SWG's actions were consistent with Staff's belief that the pipeline had significant remaining life that could have been extended with proper CP.

But for the improper repairs made by SWG personnel, the Company would not be incurring the expense of prematurely replacing the Manors' system. It is Staff's opinion that SWG customers should not have to pay for replacement of the Manors' system when it was the Company's own mistakes and improper repairs that led to the system's failure and need for replacement.

Q. Therefore, should SWG be allowed to recover from ratepayers any portion of the remaining $225,445 requested in this rate case?

A. No.

CUSTOMER OWNED YARD LINES

Q. Have you read the information pertaining to the two year pilot program proposed by SWG for the replacement of 5,000 Customer Owned Yard Lines?

A. Yes.

Q. Does Staff have any concerns with the pilot program?

A. Yes, this pilot program will only eliminate a maximum of 5,000 COYL at a cost of $10,000,000. This is only a small percentage in a small area of the 108,000 COYL estimated by SWG. Using this total, the entire replacement project would cost rate payers approximately $216,000,000. SWG has failed to provide adequate documentation delineating the effect on public safety of replacing or not replacing these lines.

Q. Does Staff have any concerns with COYL not maintained by SWG?

A. Any pipeline not maintained could cause a risk to the public. However, instead of immediately replacing these COYL, Staff recommends that SWG conduct a leak survey of all COYL to determine if there is a need for replacement of all lines or only some lines, and how lines will be selected for replacement. Based on information available, SWG estimates that this leak survey should cost approximately $3,000,000.

Q. Does Staff believe it is feasible to conduct this leak survey?

A. Yes, Staff has researched Remote Methane Leak Detection ("RMLD") technology and feels as though this is a simple and quick way to survey an area of which SWG may not have knowledge of the exact location of installed piping or may not have access to the property.

Q. What is RMLD?

A. RMLD is new technology in leak detection which allows the user to detect leaks remotely from up to 100 feet away. This would allow SWG to scan an entire property quickly without having to enter the private property.

MULTIPLE RATE CUSTOMERS

Q. Have you reviewed the information and drawings provided by SWG relevant to Multiple Rate Customers and SWG possible meter configurations for separate appliance metering submitted to the Commission by SWG on February 9, 2011?

A. Yes I have. In a March 14, 2011 letter to Steve Olea, SWG proposed three different possible customer gas meter configurations to address the issue of end-use specific rate scheduling. (See Attachment No. 3.)

Q. Would you please briefly describe each suggested configuration and state whether or not Staff supports each of the SWG proposals?

A. I will address them in the order they were presented. The first configuration includes a SWG primary meter and SWG-owned sub-meter located downstream on the customer-owned house line just ahead of the appliance it serves. This is an acceptable configuration since SWG would remain responsible for all maintenance and accuracy of the sub-meters.

In the second configuration SWG proposes to provide a primary customer meter but any sub-meters would be customer-owned. In this configuration the customer would be responsible for the cost of the sub-meter and be responsible for the maintenance and accuracy of the sub-meter. Staff does not support this configuration.

The third configuration requires SWG to provide a primary meter to be installed and provide service to individual house lines providing service to different appliances. This is also an acceptable configuration since there are no sub-meters and all metering provided is done prior to the point of transfer from the SWG-owned lines to customer-owned lines.

Q. What are your recommendations for the Multiple Rate Customers?

A. Staff agrees that both configuration numbers one and three would be acceptable and configuration number two would be unacceptable.

Q. In configuration No. 1, SWG would own meters downstream of their original meter. In Staff's opinion, who would be responsible for the maintenance of the line between the SWG original meter and the SWG downstream meter?

A. Staff believes the ownership of the line between the original SWG meter and its downstream meter should remain with the customer, so the customer would retain responsibility for that piece of the line.

EARLY VINTAGE PLASTIC PIPE REPLACEMENT

Q. Are you familiar with the 20-year replacement plan for Early Vintage Plastic Pipe ("EVPP")?

A. Yes, I am. This is a proposal for a deferral account for the replacement of all EVPP in the current SWG system.

Q. Please briefly explain what EVPP SWG is replacing?

A. As per the testimony of Jerome Shmitz with SWG, the Company has four types of EVPP - Acrylonitrile Butadiene Styrene pipe ("ABS"), Aldyl A pipe ("AA"), Aldyl High Density pipe ("AHD") and Polyvinyl Chloride pipe ("PVC").

Q. Please explain the reasons for the need to replace EVPP?

A. ABS and PVC piping is pipe that was installed prior to any code requirements and the AA and AHD piping have shown a history of becoming very brittle and failing over time.

Pipeline and Hazardous Materials Safety Administration Training and Qualifications for Scott Bryan Frye Jr.

5/24/2011 - 5/25/2011

PHMSA-PL1245 Safety Evaluation of Distribution Integrity Management Programs ("DIMP")

Participants will be able to conduct meaningful safety evaluations of distribution integrity management programs/plans. They will have a basic knowledge in specific technical areas regulated by 49 Code of Federal Regulations ("CFR") Part 192, Subpart P and risk analysis processes.

3/28/2011 – 4/1/2011

PHMSA-PL3291 Fundamentals of Supervisory Control and Data Acquisition ("SCADA") System Technology and Operation Course

The course objectives include enabling participants to make field and record inspections to determine whether the design and installation of a SCADA system is adequate, whether the operator has adequate written maintenance and inspection procedures for his/her personnel and whether these procedures have been followed. Participants will be able to determine whether the operator maintains appropriate records for system logs and alarms, as well as the necessary responses, corrections and investigations. As a result of this training, participants will also have a general knowledge of the basic design, installation, operation and maintenance of station equipment and protective systems. They will become familiar with how data is collected and properly assimilated, along with the basic analytical tools available through modeling and data analysis.

8/17/2011 – 8/20/2011

PHMSA-PL2288 Safety Evaluation of Breakout Tanks Course

Participants will be able to conduct meaningful safety evaluations of breakout tanks and their related pipeline, and be cognizant of the Office of Pipeline Safety ("OPS") inspectors' responsibilities versus those of the Environmental Protection Agency and Coast Guard inspectors. They will have a basic knowledge in specific technical areas regulated by 49 CFR Part 195, such as welding, cathodic protection, hydrostatic testing, under tank leak detection and safe repair, alterations and relocation of breakout tanks.

6/8/2010

PHMSA-PL3IC - Investigating and Managing Internal Corrosion of Pipelines Web Based Training ("WBT") Course

This WBT provides an overview of the causes, types, monitoring and remediation aspects of the corrosion process as it affects the interior walls of steel natural gas and hazardous liquid pipeline systems. Also covered are the mechanisms which trigger internal and bacterial corrosion, identification of locations where corrosion is most likely to occur, means and techniques of corrosion prevention and mitigation, field testing and sample collection, and laboratory analyses which may be utilized.

Q. Is the removal of EVPP an improvement to the safety of SWG's system?

A. Yes, Staff is an advocate of replacing these pipelines which have a history of failure or are not approved in the current editions of federal and/or state code.

Q. What does Staff recommend regarding the replacement of the EVPP, from a Pipeline Safety perspective?

A. Staff supports this project, from a safety perspective. However, with regard to Staff's position on how this should be treated from a ratemaking perspective, that will be discussed by other Staff witnesses.

USED AND USEFUL

Q. Have you examined the SWG's system with regard to used and useful?

A. Yes. During the 2011 Standard Annual Audit conducted by our office, I visited seven of the SWG districts and visited numerous field locations and projects in each district.

Q. Did you find any of the SWG system to be not used and useful?

A. No

Q. Based on Staff's Pipeline Safety 2011 Standard Annual Audit of SWG, how would you describe the general condition of SWG's system?

A. Staff did identify some Probable Non-Compliance items during its audit of SWG, but Staff did not find any items of significance and SWG adequately addressed all items identified. Staff believes that SWG's system is in good condition.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

6/8/2010

PHMSA-PL3OQ Operator Qualification WBT Course

This WBT covers basic fundamental concepts concerning the regulations, protocols, and inspection forms for gas pipelines as they relate to operators of small gas systems.

9/21/2009 – 9/25/2009

PHMSA-PL3257 Pipeline Safety Regulation Application and Compliance Procedures Course

This course addresses proper enforcement procedures associated with 49 CFR Part 190 and related State requirements for enforcement. Guidelines for deciding and taking appropriate enforcement actions are stressed through class participation in mock enforcement cases. A special attempt is made to emphasize standardization of rule application and enforcement.

9/14/2009 – 9/18/2009

PHMSA-PL2258 Safety Evaluation of Hazardous Liquid Pipeline Systems Course

This course is designed as introductory training to describe the design and operation of a hazardous liquid pipeline system in relation to 49 CFR Part 195 requirements. The training allows attendees to participate in discussions of terms, definitions and specific pipeline regulation requirements. The course will also provide guidance and fundamental training for inspectors involved in evaluating hazardous liquid pipeline facilities.

9/15/2008 – 9/19/2008

PHMSA-PL3293 Corrosion Control of Pipeline Systems Course

This course provides instruction in principles of basic electricity and corrosion, techniques for cathodic protection ("CP"), electrical potential surveys, resistance and resistivity, current requirements and Federal pipeline safety code requirements. The course also provides hands on experience with test tanks and an outdoor corrosion lab.

7/22/2008 – 7/25/2008

PHMSA-PL4253 Liquefied Natural Gas ("LNG") Safety Technology and Inspection Course

Using the knowledge gained in this course and the appropriate use of National Fire Protection Association 59 and Title 49 CFR Part 193, participants will be able to monitor LNG systems to ensure compliance with the code and be able to evaluate LNG system compliance concerning design, construction, operation and maintenance.

6/23/2008 – 6/27/2008

PHMSA-PL3254 Joining of Pipeline Materials Course

This course will provide an in-depth evaluation of joining techniques. Plastic pipe, mechanical fittings and welding will be evaluated. Proper utilization of tools and equipment associated with different joining techniques will be addressed. Participants will have the opportunity to participate in actual "hands on" joining of materials.

5/6/2008 – 5/8/2008

PHMSA-PL1255 Gas Pressure Regulation and Overpressure Protection Course

This course is presented in a job related manner that allows the participants to relate closely to actual field conditions. The training provides both classroom lectures and laboratory demonstrations with student participation during both lecture and lab portions of the course. Lecturers include audio visual media.

2/11/2008 – 2/15/2008

PHMSA-PL3256 Pipeline Failure Investigation Techniques Course

This course identifies methods and investigative techniques utilized in evaluating incidents on pipeline facilities. Experts in metallurgy, photographic documentation, explosions and fires provide fundamental instruction to help the participants recognize the different types of pipeline failures. Appropriate pipeline regulations and standards are also reviewed.

10/29/2007 – 11/2/2007

PHMSA-PL1250 Safety Evaluation of Gas Pipeline Systems Course

This course is designed as introductory training to describe the design and operation of natural gas pipeline systems in relation to 49 CFR Parts 191 and 192. The training allows attendees to participate in discussion of terms, definitions and specific pipeline regulation requirements. The course also provides guidance and fundamental training for inspectors involved in evaluating gas pipeline facilities.

ORIGINAL

ATTACHMENT 2

BEFORE THE ARIZONA CORPORATION C

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AZ CORP COMMISSION
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GARY PIERCE

32D

IN THE MATTER OF THE APPLICATION OF SOUTHWEST GAS CORPORATION FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS PROPERTIES THROUGHOUT ARIZONA.	DOCKET NO. G-01551A-07-0504 **STAFF'S NOTICE OF FILING OF DIRECT TESTIMONY**

The Utilities Division ("Staff") hereby provides Notice of Filing of the redacted Direct Testimony of Ralph C. Smith; and the Direct Testimonies of Corky Hanson; Frank W. Radigan; David C. Parcell; Phillip S. Teumim; Robert G. Gray; Rita R. Beale; and Stephen L. Thumb.

RESPECTFULLY SUBMITTED this 28th day of March, 2008.

Maureen Scott

Maureen A. Scott, Senior Staff Counsel
Kevin O. Torrey, Staff Attorney
Charles H. Hains, Staff Attorney
Legal Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Original and thirteen (13) copies
of the foregoing filed this
28th day of March 2008 with:

Docket Control
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Arizona Corporation Commission
DOCKETED
MAR 28 2008
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DIRECT

TESTIMONY

OF

RALPH C. SMITH

CORKY HANSON

FRANK W. RADIGAN

DAVID C. PARCELL

PHILLIP S. TEUMIM

ROBERT G. GRAY

RITA R. BEALE

STEPHEN L. THUMB

DOCKET NO. G-01551A-07-0504

IN THE MATTER OF THE APPLICATION OF SOUTHWEST GAS CORPORATION FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A RESONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF SOUTHWEST GAS CORPORATION DEVOTED TO ITS OPERATIONS THROUGHOUT ARIZONA

MARCH 28, 2008

BEFORE THE ARIZONA CORPORATION COMMISSION

MIKE GLEASON
Chairman
WILLIAM A. MUNDELL
Commissioner
JEFF HATCH-MILLER
Commissioner
KRISTIN K. MAYES
Commissioner
GARY PIERCE
Commissioner

IN THE MATTER OF THE APPLICATION OF SOUTHWEST GAS CORPORATION FOR JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF SOUTHWEST GAS CORPORATION DEVOTED TO ITS OPERATIONS THROUGHOUT ARIZONA.

DOCKET NO. G-01551A-07-0504

DIRECT

TESTIMONY

OF

CORKY HANSON

SENIOR PIPELINE SAFETY INSPECTOR

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

MARCH 28, 2008

TABLE OF CONTENTS

EXECUTIVE SUMMARY
SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-07-0504

The Direct Testimony of Staff witness Corky Hanson addresses the concerns of the Arizona Corporation Commission's ("Commission") Office of Pipeline Safety ("OPS" or "Pipeline Safety") relating to the Southwest Gas request to include replacement cost of the Manors subdivision gas distribution system in Yuma, Arizona.

Staff recommends the costs discussed in Staff witness Ralph Smith's testimony be disallowed from consideration in these proceedings because SWG's original intention was to extend the service life of the pipeline system by installing a new cathodic protection ground bed before incorrectly connecting the wires backwards on the rectifier causing the pipeline to corrode at an accelerated rate.

INTRODUCTION

Q. Please state your name and business address?

A. My name is Corky Hanson. My business address is 2200 N. Central Avenue, Phoenix, Arizona.

Q. What is your current position and how long have you been employed by the Arizona Corporation Commission?

A. I am a Senior Pipeline Safety Inspector; I have been employed by the Arizona Corporation Commission ("Commission") for over 15 years.

Q. Please describe briefly your duties as a Senior Pipeline Safety Inspector.

A. Briefly, my duties include conducting annual pipeline safety inspections, conducting investigations into the causes of pipeline failures, conducting pipeline construction inspections, completing required reports associated with each inspection or investigation and providing testimony on behalf of the Commission.

Q. Have you previously testified?

A. Yes, I have previously testified on behalf of the Commission.

Q. What is the purpose of your testimony in these proceedings.

A. The purpose of my testimony is to express the concerns Pipeline Safety has relating to the cost and reasons for replacing the gas distribution system in the Manors subdivision ("Manors") in Yuma.

ANALYSIS

Q. Does the Pipeline Safety Section have any concerns with Southwest Gas Corporation ("SWG" or "Southwest Gas") that would effect this rate case?

A. Yes, SWG is seeking to recover costs for the replacement in the Manors subdivision in Yuma, Arizona steel pipeline gas distribution system. Pipeline Safety does not feel that SWG should be able to recover these costs. The circumstances that necessitated the immediate replacement of this system were the direct result of incorrect actions taken by SWG personnel resulting in the failure of this system.

Q. Explain the action taken by SWG personnel that caused the failure.

A. During the SWG annual code compliance audit in 2006, it was noted on the inspection report that SWG had not taken prompt remedial action to correct deficiencies of the Manors cathodic protection ("CP") identified during the annual CP monitoring. The CP deficiency was identified on March 26, 2004. Remedial action was not completed until February 28, 2006. Failure to provide adequate CP on a steel pipeline system can lead to deterioration of the pipeline resulting in leaks and ultimately the replacement of the pipeline. The technician responsible for making repairs to the CP rectifier system connected the wiring backwards (positive to negative / negative to positive). This action caused the pipeline to corrode at an accelerated rate resulting in multiple corrosion failures and necessitating the immediate replacement of the steel pipeline system. SWG management personnel did not identify this mistake until the system failed and required replacement.

Q. Briefly explain what cathodic protection is and its importance in protecting the pipeline.

A. Pipe corrosion is one of the leading causes of pipeline failures. CP is a procedure by which an underground metallic pipe is protected against corrosion. A direct current is impressed onto the pipe by means of either a sacrificial anode or a rectifier. CP monitoring is conducted once each calendar year to ensure that minimum CP is being maintained on the pipeline. The duration between inspections should not exceed 15 months.

Q. Briefly explain what a rectifier is, how it operates and the consequences of improper installation.

A. A CP rectifier is a device that converts alternating current ("AC") into direct current ("DC") for use with cathodic protection. The proper way to use a rectifier is to connect the positive (+) wire terminal to the anode, and the negative (-) wire terminal to the pipeline making the pipeline the cathode. In a properly installed system it is the anode that loses current taking material with it until its mass is depleted thereby mitigating corrosion on the cathode (pipeline). Reversing the wire connection (polarity) would cause the pipe to become the anode, resulting in accelerated corrosion of the pipeline. Southwest Gas claims that this rectifier was maintained and initialized by the same Southwest Gas employee who was responsible for the Company's failure to conduct the CP monitoring in 2006.

Q. Based on your experience, could the Manors steel pipeline system have lasted for many more years if adequate CP had been properly applied?

A. Yes, based on my CP training and experience both as an operator and Pipeline Safety Inspector, this system could have lasted for many more years. I also consulted with coworkers Marion Garcia (Chemical Engineer) and Ryan Weight (Mechanical Engineer). Both also have extensive cathodic protection experience, and both agree with my assessment of this system. Pursuant to regulations, SWG had the option to either replace the pipeline with plastic pipe (which does not require cathodic protection), or install CP. Ground bed anodes on impressed current systems are normally designed to last, at a minimum, 20 years. When SWG made the decision to replace the ground bed instead of replacing the pipelines it was evident that the pipeline was in a condition that could be preserved. Clearly, the intent was to extend the service life of the system. For SWG to expend the cost and effort to replace the CP ground bed to restore CP to the Manors' steel system, it is obvious that SWG planned on these actions extending the service life of this system. Through only 11 months of operation using an incorrectly installed rectifier, the pipeline was corroded to the point of being no longer operable. It is true that the pipeline had been in service for 50 years. However, as SWG's service life extension efforts demonstrate, there was no present need to replace the pipeline. SWG's actions are consistent with Staff's belief that the pipeline had significant remaining life that could have been extended with proper cathodic protection.

But for the improper repairs made by an SWG field technician, the Company would not be incurring this expense. Customers should not have to pay for a new system when the Company's own mistakes and improper repairs lead to the system's failure and need for replacement.

Q. Have you reviewed the list of 68 contracts provided by SWG to determine whether the projects were used and are useful?

A. Yes.

Q. Does the Pipeline Safety Section have any additional concerns regarding the used and useful analysis of the list of 68 contracts that would affect this rate case?

A. No.

RECOMMENDATIONS

Q. What is your recommendation in this case?

A. I recommend that SWG be permanently disallowed from including the cost relating to the Manors replacement project for consideration in this rate case and any future rate cases. Staff witness Ralph Smith addresses the calculation of the disallowance in his testimony.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

SOUTHWEST GAS CORPORATION

MAR 15 2011

Jerome T. Schmitz, P.E., Vice President/Engineering

March 14, 2011

Steve Olea, Director Utilities Division
Arizona Corporation Commission
1200 W. Washington Street
Phoenix, AZ 85007

Subject: Multiple Rate Customers

Dear Steve:

Thank you for meeting with Southwest Gas Corporation (Southwest) representatives on February 9, 2011 to discuss metering options for billing customers with multiple rates for different loads.

As we discussed, Southwest has several tariff rate schedules applicable to specific end-use applications for natural gas. These rate schedules provide cost-of-service pricing based on energy-efficient uses of natural gas. Included in these schedules is Rate Schedule No. G-40, which is applicable to natural gas used for air conditioning. In order for customers to receive the benefit of end-use specific rate schedule pricing, the volumes for the end-use appliance(s) must be separately metered. Furthermore, recent advances in technology have resulted in smaller scale gas air conditioning equipment increasing the likelihood that customers will choose to connect air conditioning appliances to their existing house line versus constructing a dedicated supply line. This may result in a mingling of loads beyond the outlet of Southwest's customer meter thus preventing the proper billing of the customer's gas air conditioning equipment.

As we discussed during our meeting, Southwest identified three options to address this billing and metering issue (see attachment). Based upon our discussions, it is Southwest's understanding that the preferred approach by all parties (Southwest, you, and your Safety Staff) are Options 1 and 3, depending upon the circumstances of the customer. For instance, Southwest may utilize custody transfer meters in situations where installation is feasible (Option 3). Where two Southwest custody transfer meters are infeasible for the specific end-use appliance(s), a Southwest-owned end-use meter downstream of Southwest's custody transfer meter may be used to obtain metered volumes for billing (Option 1). Notwithstanding the installation of an end-use meter pursuant to Option 1, the parties agreed that this should not result in any change in the exercise of jurisdiction by your Safety Staff. The parties also agree that customer-owned end-use meters (Option 2) will not be utilized.

Thank you for the opportunity to discuss these items with you and your Safety Staff. Please confirm your agreement with our understanding of how to address this billing and metering issue by countersigning the enclosed copy of this letter and returning it to my attention.

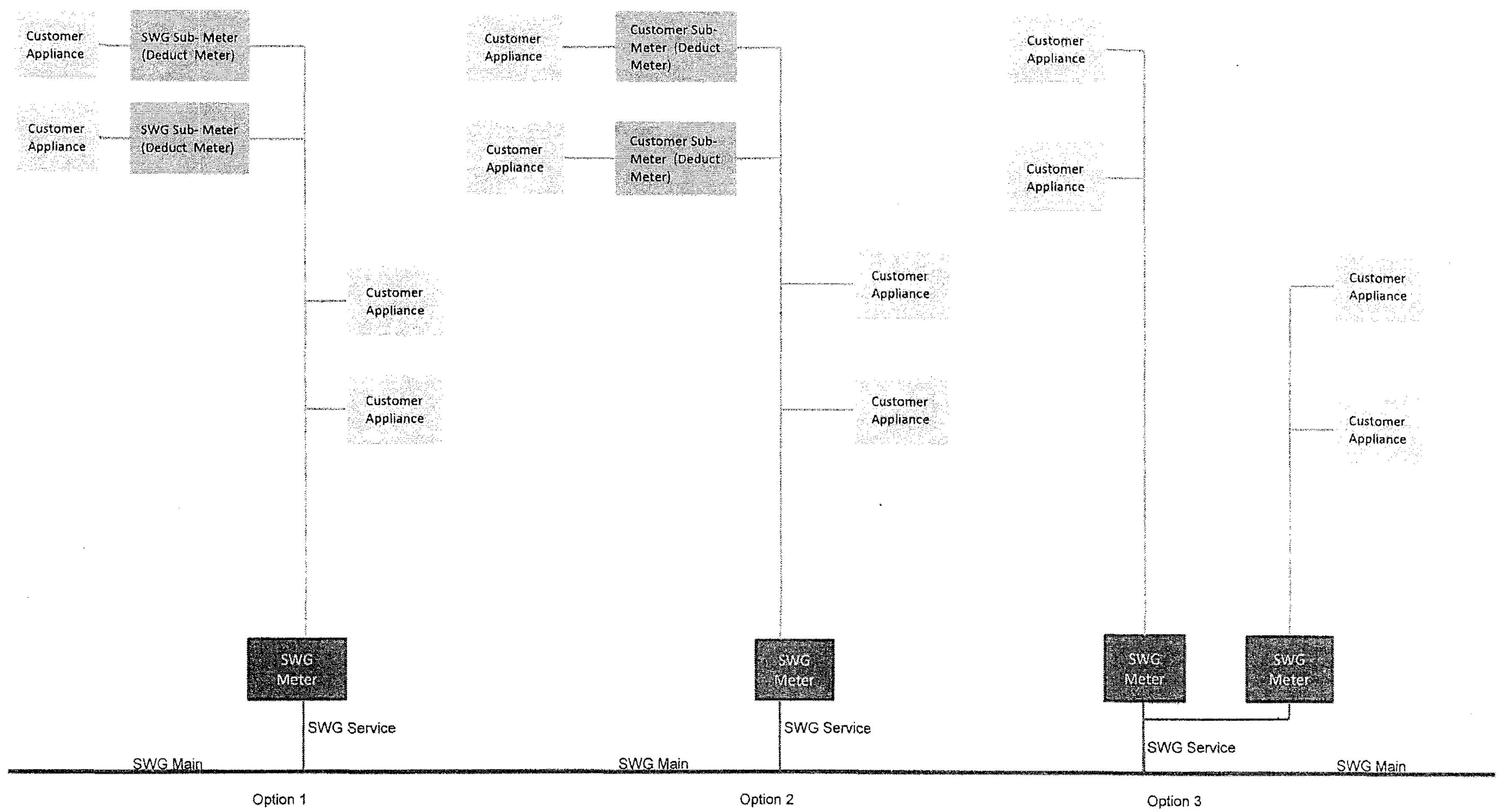
Sincerely,

Attachment

Reviewed and Agreed to by:

____
Steve Olea, Director, Utilities Division
Arizona Corporation Commission

cc: Robert Miller, ACC
Corky Hanson, ACC
Debi Gallo, SWG
Jose Esparza, SWG
Randy Ortlinghaus, SWG
Ron Bassler, SWG
Brooks Congdon, SWG
Dan Bryant, SWG
Lynn Malloy, SWG



Customer Appliance
SWG Sub- Meter (Deduct Meter)
Customer Appliance
SWG Sub- Meter (Deduct Meter)
Customer Appliance
Customer Appliance
SWG Meter
SWG Service
SWG Main
Option 1
Customer Appliance
Customer Sub-Meter (Deduct Meter)
Customer Appliance
Customer Sub-Meter (Deduct Meter)
Customer Appliance
Customer Appliance
SWG Meter
SWG Service
SWG Main
Option 2
Customer Appliance
Customer Appliance
Customer Appliance
Customer Appliance
SWG Meter
SWG Meter
SWG Service
SWG Main
Option 3

BEFORE THE ARIZONA CORPORATION COMMISSION

GARY PIERCE
Chairman
BOB STUMP
Commissioner
SANDRA D. KENNEDY
Commissioner
PAUL NEWMAN
Commissioner
BRENDA BURNS
Commissioner

IN THE MATTER OF THE APPLICATION OF SOUTHWEST GAS CORPORATION FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS PROPERTIES THROUGHOUT ARIZONA	DOCKET NO. G-01551A-10-0458

DIRECT

TESTIMONY

OF

JULIE MCNEELY-KIRWAN

PUBLIC UTILITIES ANALYST IV

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JUNE 10, 2011

EXHIBIT
S-7
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TABLE OF CONTENTS

EXHIBITS

EXECUTIVE SUMMARY
SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-10-0458

Southwest Gas Corporation ("Southwest" or "Company") provides natural gas service to approximately a million Arizona customers in the following counties: Cochise, Gila, Graham, Greenlee, La Paz, Maricopa, Mohave, Pima, Pinal and Yuma. Southwest's customers are primarily Residential (945,000), but it also has 40,000 Commercial customers, as well as a small number of customers in other classes, such as Industrial, Irrigation, and Transportation.

In this testimony, Staff will address the Company's proposed Energy Efficiency and Renewable Energy Resources Technology Portfolio Implementation Plan. The Portfolio consists of ten programs designed to meet the Gas Utility Energy Efficiency Standards.

With respect to the Implementation Plan, Staff concludes the following:

- Based on the information and data currently available to Staff at the time of this testimony, it is Staff's belief that the pilot programs, as proposed, are not cost-effective.

- Cost-effectiveness analysis was performed by Southwest at the program level, making the information in the Implementation Plan (i) inconsistent with previous energy efficiency filings and (ii) insufficient for determining the benefit-cost ratios of new measures. Measure-level analysis and data are required in order to determine the cost-effectiveness of individual measures and their probable effect on the overall cost-effectiveness of a program or group of programs. The data currently available indicate that at least some of the proposed new measures are unlikely to be cost-effective.

- The complexity of the portfolio (10 programs, five of them new, multiple new measures), and the size of the proposed budget ($16.5 million), require a level and type of analysis such that a rate case may not be the best venue, particularly given the need for more data on the proposed pilot programs and new measure.

- Staff recommends that the Implementation Plan not be approved at this time, and that the Company refile its Implementation Plan in a separate docket.

- Staff recommends that the timing for application of the 2011 standard be determined in that separate docket.

- Staff also recommends that the demand-side management adjustor rate remain unchanged until further Commission action in the separate docket recommended above.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Julie McNeely-Kirwan. I am a Public Utilities Analyst IV employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as a Public Utilities Analyst IV.

A. My duties as a Public Utilities Analyst IV include reviewing and analyzing applications filed with the Commission, and preparing memoranda and proposed orders for Open Meetings. In addition, my duties have included preparing written testimony in multiple rate cases, and testifying during the related hearings. I have also assisted in the management of rate cases and have performed evaluations of energy efficiency implementation plans.

Q. Please describe your educational background and professional experience.

A. In 1979, I graduated Magna Cum Laude from Arizona State University, receiving a Bachelor of Arts degree in History. In 1987, I received a Master's Degree in Political Science from the University of Wisconsin, Madison. I have been employed by the Commission since September of 2006. Since that time, I have attended a number of seminars and classes on general regulatory issues, including demand-side management and the gas and electric industries.

SCOPE OF TESTIMONY

Q. What is the scope of your testimony in this case?

A. Staff will address Southwest Gas Corporation's ("Southwest" or "Company") proposed Energy Efficiency and Renewable Energy Resources Technology Portfolio

Implementation Plan ("EE and RET Implementation Plan"), as filed within the 2010 Arizona General Rate Case for Southwest.

THE IMPLEMENTATION PLAN

Q. Did the Commission adopt new rules on energy efficiency for natural gas utilities?

A. Yes. On December 10, 2010, the Commission adopted new rules on energy efficiency ("EE") for gas utility companies ("Rules" or "Standards"), with standards requiring annual and cumulative savings. Pursuant to the rules, each affected gas utility is required to achieve cumulative annual energy savings, expressed as therms or therm equivalents, equal to at least 6 percent of retail sales for calendar year 2019, by December 31, 2020.

Q. Do the new rules require than an Implementation Plan be filed?

A. Yes. Section R14-2-2505 of the Arizona Administrative Code ("A.A.C.") requires that an Implementation Plan be filed by June 1 of each odd year, or annually, at the utility's election, describing how each utility plans to meet the EE Standard for the next one or two years. An exception was made for each utility's initial Implementation Plan, which was ordered to be filed within 30 days of the effective date of the new Standards (March 4, 2011).

Q. Did Southwest file an Implementation Plan?

A. Yes. In compliance with the new gas energy efficiency rules, Southwest filed an Implementation Plan as part of its general rate case application (filed on November 12, 2010.) Southwest requested that the Implementation Plan filed within the rate case be treated as its first Implementation Plan, under the Rules.

Q. What is the scope of the Implementation Plan?

A. The EE and RET Implementation Plan describes how Southwest intends to meet the new gas Standards over a two-year period.

THE NEW GAS STANDARDS

Q. Please describe the requirements of the new gas Standards and how they can be met by affected utilities.

A. Pursuant to A.A.C. R14-2-2504, by the end of 2011, Class A affected gas utilities are required to achieve energy savings equal to 0.50 percent of their retail energy sales in 2010. At least 75 percent of those therms, or therm equivalents must be saved through energy efficiency Demand-Side Management ("DSM") programs. In addition to their own energy efficiency programs, affected gas utilities may count the energy savings arising from any customer's self-directed DSM program or programs toward this portion of the requirement.

The remaining 25 percent of required therms, or therm equivalents, may be saved outside of energy efficiency DSM programs, meaning through Combined Heat and Power ("CHP") programs, renewable energy resource technology ("RET") programs, and through building codes and appliances standards.

Q. Please provide more detail regarding how a gas utility could meet 25 percent of its required therm savings through building codes, appliance standards and sponsorship of RET programs that displace gas.

A. An affected gas utility may count up to one-third of the energy savings resulting from energy efficiency building codes and appliance standards. In order to do this, a gas utility must demonstrate and document its efforts to support the adoption and implementation of energy efficiency codes for buildings and appliances. Gas utilities may also count all energy savings resulting from its sponsorship of RET projects that displace gas. The gas utility may also count energy savings from RET projects not sponsored by that utility if the utility can demonstrate that its efforts facilitated the placement and completion of the RET project or projects.

Q. How does Southwest, specifically, propose to meet the new gas utility energy efficiency standard?

A. In its Implementation Plan, Southwest proposes to achieve most of its required therm or therm equivalent savings through the ten programs comprising its EE and RET Portfolio.

The Company plans to achieve the remainder of its required therm or therm equivalent savings though its efforts "to support the adoption and implementation of . . .energy efficiency building codes, as well as the Company's involvement in the placement of non-Company sponsored RET projects that displace gas. . . ."

PROPOSED BUDGET

Q. What is the proposed budget for the EE and RET portfolio, as described in the Implementation Plan?

A. The Company has proposed a budget of $16.5 million, an approximately $11.7 million increase from the currently approved approximately $4.8 million portfolio budget. The Company's per-program and per-category budget proposal, as proposed by Southwest, is attached as Exhibit 1.

Q. What is the rationale for the budget increase proposed by the Company?

A. Southwest explains that "[T]he proposed budget affords the Company a level of funding adequate to sustain the programs and allow the Company to achieve the goals set forth in the preliminary Standards."

The Company also states that the proposed budget maximizes the funding going to customers though education, training, incentives and technical assistance, and takes into account the costs of ramping up and administrative oversight.

THE PROPOSED SOUTHWEST EE AND RET PORTFOLIO

Q. Please generally describe the proposed Southwest Energy Efficiency and Renewable Energy Resource Technology Portfolio.

A. The proposed portfolio consists of ten new and existing programs, all named (or renamed) to reflect the Company's new *Smarter Greener Better* ("SGB") brand.

The portfolio consists of three Residential programs, four Non-residential programs, one Low-Income program (including weatherization and bill assistance components), one Educational program and one RET program.

Brief descriptions of each program are provided in the table below. Exhibit 2, attached herein, is an excerpt from the Company's filing, and provides a more detailed narrative description of each program.

Q. Does Southwest currently have an EE program in place?

A. Southwest has a DSM portfolio consisting of seven energy efficiency programs, three Residential (including one Low-Income program) and four Non-Residential.

Q. Why is the term "DSM" used to describe the current Southwest portfolio?

A. The terms "DSM" and "energy efficiency" are often used interchangeably, but "DSM" is actually a broader term that includes both energy efficiency and (for gas programs) CHP programs.[1]

Q. Please list the programs in Southwest's existing portfolio.

A. Southwest's current portfolio consists of the following programs : (i) Low-Income Energy Conservation (Residential; low-income); (ii) *SGB* Homes (Residential; new construction); (iii) Consumer Products (Residential; existing homes); (iv) Commercial Equipment (Non-residential; commercial cooking equipment); (v) Large Commercial Energy-Efficiency Boilers (Non-residential; boilers and boiler-related measures); (vi) Technology Information Center (Non-residential; energy efficiency newsletter) and (iv) Distributed Generation (Non-residential; CHP generation).

Q. What criteria are used when Staff reviews energy efficiency programs submitted for approval by utilities?

A. The main basis for evaluating energy efficiency programs or measures is cost-effectiveness on a measure level. The component measures for any new programs are each reviewed for cost-effectiveness, and measures being added to existing programs are reviewed individually for cost-effectiveness.

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[1] Under the Gas Utility Energy Efficiency Standards, CHP can be counted toward meeting the Standard after at least 75% of the Standard has been met through energy efficiency.

Q. Can you describe how the proposed EE and RET portfolio differs from the Company's existing portfolio and indicate which programs are newly proposed, which are existing, and, for the existing programs, indicate which measures are newly proposed.

A. Yes, that is done in the table below.

Program Name	Sector	Type (New/Existing) and Description	Changes (for existing programs)
SGB Residential Rebates	Residential	**Existing.** Offers rebates to Residential customers to promote energy efficient appliances and weatherization for existing homes.	Proposed new measures: condensing water heaters, lavatory faucets, dishwashers, furnaces and boilers, and weatherization measures, including windows, insulation and duct sealing.
SGB Homes	Residential	**Existing.** Offers rebates to homebuilders to build Energy Star certified homes and install Energy Star appliances and insulation.	Proposed new measures: condensing water heater, clothes washer, clothes dryer, and insulation. Company also proposes to revise standards for existing measures, to meet Energy Star standards
SGB Residential Energy Assessments	Residential	**New (pilot).** Offers rebates to homeowners for energy audits. Also offers direct install efficient showerheads and faucets.	N/A
SGB Business Rebates	Non-residential	**Existing.** Offers rebates to Non-residential customers for installing energy efficient appliances (boiler and commercial kitchen measures) and weatherization measures.	Proposed new measures: clothes washers, large vat fryers, convection ovens, conveyer ovens, dishwashers, windows, insulation, air curtains. Combines the existing Commercial Equipment and Boilers programs
SGB Custom Business Rebates	Non-residential	**New (not proposed as a pilot).** Offers rebates based on achieved annual energy savings.	N/A
SGB Business Energy Assessments	Non-residential	**New (pilot).** Offers rebates for comprehensive energy audits.	N/A
SGB Distributed Generation	Non-residential	**Existing.** Offers rebates to Non-residential measures for installing high efficiency CHP technologies.	Proposes a large increase in budget to accommodate potential additional projects.
SGB Low-Income Energy Conservation	Low-Income	**Existing.** Provides weatherization measures to low-income customers. Includes bill assistance.	No significant changes are being proposed for this program
SGB Energy Education	Energy Education, Residential and Non-residential.	**New (pilot).** (Includes existing Technology Information Center program.) Provides customers with energy efficiency and conservation information.	N/A
SGB Solar Thermal Rebates	Renewable, Residential and Non-residential.	**New (not proposed as a pilot).** Offers rebates to Residential and Non-residential customers to promote solar thermal systems for water heating and pool heating.	N/A

Q. Has Staff reviewed and performed any analysis of the Company's proposed EE programs?

A. Yes. Although the information provided in the Implementation Plan is insufficient to perform a full analysis regarding the cost-effectiveness of the proposed new programs and measures, Staff has been able to determine that there are basic issues with the Southwest Implementation Plan, both in terms of the data and analysis provided, and in terms of the probable cost-effectiveness of proposed new programs and measures.

Q. Based on Staff's review, what is Staff's recommendation?

A. Staff recommends that the Implementation Plan not be approved at this time, and that the Company refile its Implementation Plan in a separate docket, with cost-effectiveness analysis and data provided at the measure level, as required by the rules. Refiling in another docket will allow Staff the opportunity to perform its due diligence based on measure-level cost-effectiveness information.

Q. Please briefly explain Staff's issues with respect to the Company's Implementation Plan.

A. There are three basic issues that concern Staff with respect to the Southwest Implementation Plan: (i) limited data and lack of cost-effectiveness for DSM Pilot Programs; (ii) the program-level analysis of cost-effectiveness provided by the Company; and (iii) the appropriateness of a rate case as a venue for reviewing a portfolio of this size and complexity. All three of these issues are discussed in more detail below.

Q What pilot programs did Southwest propose as part of its Implementation Plan?

A. Southwest is proposing three energy efficiency pilot programs: *SGB Residential Energy Assessments, SGB Business Energy Assessments,* and *SGB Energy Education.* The energy assessment programs provide incentives to Residential and Non-Residential customers for energy audits, and the education program is designed to promote energy efficiency and conservation among both Residential and Non-residential customers. (Please see Exhibit 1 for the pilot program budgets.)

Q. Please describe Staff's concern regarding the limited data and lack of cost-effectiveness for the pilot programs.

A. Southwest has interpreted the new gas Standards to mean that cost-effectiveness is not required for DSM pilot programs. The Company did not provide benefit-cost ratios for the three proposed pilots in its Implementation Plan, and provided only limited information regarding the costs and benefits for two of the pilots in either the Implementation Plan or the spreadsheets provided in response to data requests. The information provided by the Company so far indicates that, for all three pilot programs, costs greatly exceed benefits. (See Southwest's Table 1, attached as Exhibit 3 to Staff's testimony.)

Q. Is the Company's position correct?

A. No. Affected utilities are required to design each DSM program to be cost-effective and to provide cost-effectiveness data for each proposed DSM program or measure. (See R14-2-2503.A and R14-2-2507.) Pilot programs are not exempted from these requirements.

Although Southwest states that it is "optimistic" that the proposed pilot programs will be cost-effective, the information and data currently available to Staff do not indicate that these programs were either designed to be cost-effective or likely to become cost-effective in the future. In addition, Staff does not believe that the data provided meets the requirements under the rules.

Q. Please describe Staff's concern regarding the program-level cost-effectiveness analysis provided for the Company's portfolio of programs.

A. Southwest has provided cost-effectiveness analysis at only the program level, including for existing programs for which new measures have been proposed. Although some measure-level data has been provided, it is insufficient for purposes of producing a reasonable estimate of individual measure cost-effectiveness. Without the ability to reasonably estimate the cost-effectiveness of the new measures, Staff can not assess whether they represent a reasonable investment of ratepayer dollars, or determine their potential impact on the overall cost-effectiveness of the Company's DSM programs.

As with the pilot programs, Staff also does not believe that the data provided meets the requirements under the Rules.

Q. Please describe Staff's concern regarding the appropriateness of a rate case, in terms of evaluating a portfolio of this size and complexity.

A. The complexity of the portfolio (10 programs, five of them new, multiple new measures) and the size of the proposed budget ($16.5 million) require a level and type of analysis such that a rate case, with its timeline, may not be the best venue. This is particularly true in light of Staff's issues with the data provided so far in the rate case.

PILOT PROGRAM DATA AND COST-EFFECTIVENESS ISSUE

Q. Did Staff ask for the estimated cost-effectiveness of the pilot programs in its data requests?

A. Yes.

Q. Did Southwest provide Staff with the benefit-cost information Staff requested?

A. No. Southwest did not supply these estimates in its response, and stated that it "has not calculated cost-effectiveness for the DSM pilot programs proposed as part of the Implementation Plan." The Company went on to cite the following language from R14-2-2512.G of the Rules: ". . .pilot programs are not required to demonstrate cost-effectiveness."

Q. Was any information provided in response to Staff's data requests which shed light on the cost-effectiveness of the pilot programs?

A. Yes. In response to another data request, the Company provided electronic spreadsheets with program-level costs and benefits for the *SGB Residential Assessments* pilot program, and program-level costs only (with zero benefits) for the *SGB Commercial Assessments* and *SGB Education* pilot programs. The benefit-cost ratios, although not provided in the filing, appeared in the spreadsheets as 0.11 for the *SGB Residential Assessments* program, and as zero for the other two pilot programs.[2]

In its response to Staff's inquiry about whether these spreadsheets reflected the actual cost-effectiveness of the three pilots, the Company responded that "individual cost-effectiveness value is not calculated for each pilot program, [but] the costs to implement them are included in the portfolio cost-effectiveness calculation."

[2] In Response to ACC-STF-12-2 Southwest stated that "Although the individual cost-effectiveness value is not calculated for each pilot program, the costs to implement them are included in the portfolio cost-effectiveness calculation."

Q. Under the Standards, what cost-effectiveness data must be provided as part of every program proposal submitted to the Commission?

A. The Standards specifically state that each proposal "shall include" estimated societal benefits, and savings and costs, along with estimated customer participation and an estimated benefit-cost ratio, as well as other information.

Q. Do data requirements for Education programs differ from requirements for other programs?

A. No, but for Education programs, cost-effectiveness analysis is based on estimating the impact of increased awareness. The Standards state that "[e]ducational programs shall be analyzed for cost-effectiveness based on estimated energy and peak demand savings resulting from increased awareness about energy use and opportunities for saving energy."

Q. Was information on estimated energy and peak demand savings provided for the *SGB Energy Education* program?

A. No.

Q. Based on the information received from the Company to date, is there sufficient information for Staff to independently (and reasonably) estimate the benefit-cost ratios for any of the pilot programs?

A. No.

Q. Does Staff believe that the information provided by the Company in the spreadsheets indicates that the cost of the pilots greatly exceeds the benefits?

A. Yes.

Q. Does Staff agree with Southwest's interpretation of the language in R12-2-2512.G, which states that "pilot programs are not required to demonstrate cost-effectiveness"?

A. No.

Q. What is Staff's interpretation of this language?

A. The language of R12-2-2512.G is from the "Cost-effectiveness" section of the new gas Standards. It means that a program may be continued, even when it has not demonstrated cost-effectiveness during the pilot phase, if there is a reasonable expectation that the program will become cost-effective once fully implemented and active. Staff also interprets R12-2-2512.G to mean that a utility may recover prudently incurred DSM costs, even if a pilot program does not demonstrate cost-effectiveness in practice.

The language of R12-2-2512.G does not mean that a utility can simply label a proposed program as a "pilot" and thereby relieve itself from designing the program to be cost-effective, from determining its cost-effectiveness under the Societal Test, or from providing the information set out in the Standards under "Commission Review and Approval of DSM and RET Programs."

PROGRAM-LEVEL ANALYSIS ISSUE

Q. Is the cost-effectiveness analysis and data provided by the Company in its EE and RET Implementation Plan filing consistent with earlier Southwest filings for energy efficiency programs and measures?

A. No. Earlier Southwest filings for DSM programs, and for new measures being added to existing programs, provided cost-effectiveness analysis and data at the measure level.

Q. Can you provide examples?

A. Yes. Southwest filings with cost-effectiveness analysis and data provided at the measure level include Southwest's 2006 Demand Side Management Program Plan, filed in compliance with Decision No. 68487 (Docket No. G-01551A-04-0876), Southwest's Application to Continue and Modify the Demand Side Management Consumer Products Program (Docket No. G-01551A-08-0619), and Southwest's Proposal to Supplement and Modify its Arizona Demand Side Management Plan for Program Years 2009 and 2010 (Docket No. G-01551-09-0039).

Q. Did Southwest provide measure-level cost-effectiveness analysis, or estimated benefit-cost ratios, for the new measures proposed in its Implementation Plan?

A. No, but the Company did supply measure-level savings and incremental costs.

Q. Why is Staff concerned about the use of program-level analysis in the Southwest Implementation Plan?

A. Program-level analysis can mask non-cost-effective individual measures by combining the costs and benefits for multiple measures. Based on the incremental costs and savings for some measures, it is extremely unlikely that some of the new measures proposed by Southwest would be cost-effective. Other measures (with higher savings compared to costs) may be cost-effective, but the lack of a measure-level data and analysis leaves this uncertain.

Q. Why is Staff concerned about the lack of measure-level estimates for participation?

A. Without measure-level participation estimates, Staff can not reasonably allocate program costs for individual measures in some multiple-measure programs and can not, as a result, independently calculate cost-effectiveness.

The lack of estimates on measure-level participation also makes it impossible to reasonably estimate the potential impact of individual measures on cost-effectiveness of programs, or on the DSM programs as a whole.

Q. Please provide specific examples from Southwest's Implementation Plan of measures that are unlikely to prove cost-effective in practice.

A. Two examples from the *SGB Residential Rebates* program are the Standard and Compact Dishwasher Models. In its Implementation Plan, Southwest stated an incremental cost of $126 for the Standard Dishwasher Model, but only a 1.3 annual therm savings. For the Compact Dishwasher Model, Southwest stated a $100 incremental cost, but annual savings of only 1 therm. It is clear, even without calculating a benefit-cost ratio, that the payback for customers on the incremental costs would greatly exceed the lifespan of either measure (for dishwashers, generally up to 13 years).

Staff initially estimates a benefit-cost ratio for both measures (based on the limited information currently available) of 0.04, far below the 1.0 that would be required to make the measures cost-effective, without customer water savings. Annual customer water savings of 323 gallons and 215 gallons, respectively, would improve the benefit-cost ratios, but not by enough to approach cost-effectiveness.

Q. Please provide specific examples from Southwest's Implementation Plan of measures likely to prove cost-effective in practice.

A. Based on Staff's initial estimates, and the limited information currently available, Staff believes that the Residential Boiler measure may have a benefit-cost ratio of approximately 1.03. While the information provided by the Company in support of its incremental costs and therm savings for the *SGB Residential Rebates* program is not sufficiently specific to verify. Staff's research determined that the Company's estimate on incremental cost was reasonable and may even have been conservative as to savings (suggesting that actual cost-effectiveness for this measure may be higher than 1.03.)

Q. Are there any other reasons to establish the per-measure cost-effectiveness of proposed measures?

A. Yes. Per-measure cost-effectiveness analysis highlights instances when non-incentive costs may be too high, and identifies which measures are likely to produce the most savings for the DSM dollars being invested. These opportunities to develop information allowing for the more efficient allocation of DSM dollars are lost without the per-measure analysis.

RATE CASE VENUE

Q. Does Staff believe that Southwest's Implementation Plan should be approved as part of the current rate case?

A. No. Due to the issues with the data provided, as discussed herein, and due to the size and complexity of the Company's EE and RET Portfolio, Staff believes that the Implementation Plan should be refiled in another docket.

OTHER ISSUES

Q. Other than the three main issues discussed herein, are there other Staff concerns with respect to the information provided in the rate case Implementation Plan filing?

A. Yes. The Company's methods for calculating projected energy savings are unclear, as is its basis for determining lifespans for multiple-measure programs. For this reason, Staff is unable to determine whether the Company's assumptions are reasonable.

COST-EFFECTIVENESS REQUIREMENTS UNDER THE NEW GAS STANDARDS

Q. Please describe the requirements for measure cost-effectiveness under the new gas Standards.

A. Each and every measure must be designed to be cost-effective or (as with education programs) designed to measurably enhance the cost-effectiveness of the EE portfolio as a whole.

Q. Why?

A. If a measure is not cost-effective, or can not measurably enhance the cost-effectiveness of an EE program or programs, there is no reason to use ratepayer dollars to promote that measure. Even in cases where a program or portfolio can absorb non-cost-effective measures and remain cost-effective on an overall basis, any non-cost-effective measure, or program, dilutes that cost-effectiveness.

Measure cost-effectiveness is also required to meet the requirements of the rules. R14-2-2512.A states that an affected utility "shall ensure that the incremental benefits to society of the affected utility's overall group of DSM programs exceed the incremental costs to society of the overall group of DSM programs." The only way to ensure that benefits exceed costs for DSM programs as a whole is to ensure the cost-effectiveness, or contribution to cost-effectiveness, of each component program, and the only way to ensure the cost-effectiveness of each program is to ensure the cost-effectiveness, or contribution to cost-effectiveness, of each component measure.

Q. Must each and every DSM program be designed to be cost-effective under the new gas Standards?

A. Yes. R14-2-2503.A (referred to elsewhere, herein) states that "An affected utility shall design each DSM program to be cost-effective."

REQUEST TO POSTPONE 2011 ENERGY EFFICIENCY STANDARD

Q. Does Southwest anticipate meeting the energy efficiency standards set for gas utilities for 2011?

A. No. In Paragraph 6.3 of its General Rate Case application, the Company states that it "does not anticipate that the EE and RET Plan will be approved and implemented in time for the Company to have a reasonable opportunity to achieve the .50 percent standard for the calendar year 2011." Based on its current DSM portfolio, Southwest anticipates therm savings of 2,281,000 during calendar year 2011.

Q. What level of savings would this equal, in terms of the new gas energy efficiency Standard?

A. Staff estimates that this level of savings, if achieved, would equal approximately 75 percent of the 2011 standard.

Q. Does Staff anticipate that Southwest will achieve additional savings during calendar year 2011 that would qualify under the new gas energy efficiency standard?

A. Yes. The Company states that it has worked, and continues to work, in support of the adoption and implementation of building codes. This work includes: (i) participating in the City of Phoenix Energy Phoenix program (which also leverages existing utility programs); and (ii) supporting adoption of the 2009 International Energy Conservation Code ("IECC") by the City of Mesa.

Under the gas energy efficiency rules, as discussed elsewhere in this testimony, one-third of the savings from these activities can be counted toward meeting the energy efficiency standards.

Q. Does Staff know the number of therms or therm equivalents that would be saved in 2011 through Southwest's efforts to promote energy efficiency?

A. No. The savings achieved would depend on factors such as participation and new home construction levels,[3] and would have to be documented and verified. Staff believes, however, that the potential savings from building codes are significant, even taking into account that only up to one-third of savings from this source can be counted toward the Standard.

Q. Why does Staff think the savings are potentially significant?

A. Energize Phoenix is a $25 million program to reduce Residential energy consumption by up to 30 percent and commercial energy consumption by 18 percent. With respect to Mesa's adoption of an enhanced building code, the 2009 IECC would increase energy savings for new homes by approximately 12-15 percent, as compared to the 2006 IECC.

Q. Does Staff anticipate that Southwest will achieve any other savings during calendar year 2011 that would qualify under the new gas energy efficiency standard?

A. Yes. Southwest is currently sponsoring RET projects to displace gas. Southwest states that "the Company will continue to work with its customers to deliver the most efficient unit of energy, including the installation of natural gas-displacing applications such as solar."

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[3] 6,000 new homes are estimated for the Phoenix metropolitan area (which includes Mesa) in 2011.

Q. Has Southwest requested that the energy efficiency standards set for gas utilities for 2011 be permanently waived for Southwest?

A. No. Southwest requests that that it "be authorized to apply the 2011 standard to the first 12-month period following approval and implementation of the Company's EE and RET Plan."

Q. Does Staff agree with Southwest's request to apply the 2011 standard to the first 12-month period following approval and implementation of the Company's Implementation Plan?

A. No. Staff does not believe that Southwest's request to postpone application of the 2011 standard should be acted upon at this time. Instead, Staff recommends that the Implementation Plan not be approved at this time and that the Company refile its Implementation Plan in a separate docket. Staff also recommends that the timing for application of the 2011 standard (0.50 percent of previous year's retail energy sales) be determined in that separate docket. In addition, Staff recommends that the DSM adjustor rate should remain unchanged until further Commission action.

Removing the Implementation Plan from the rate case will allow the Company time to develop and file the additional data and analysis required for the Commission to adequately evaluate the proposed EE and RET portfolio, particularly the measure-level data and analysis required in order to determine whether individual measures are cost-effective and how adding these new measures and programs will impact overall portfolio cost-effectiveness. Removal to a separate docket will also afford the Company an opportunity to provide additional information and data concerning the pilot programs, and would provide the Commission with the time needed to evaluate the new information.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

EXHIBIT 1 – Southwest Portfolio Annual Estimated Budget

Program	Rebates	Administration	Outreach	Delivery	Evaluation	Program Total Cost
Residential						
Residential Rebates	$3,850,000	$41,250	$330,000	$1,196,250	$82,500	$5,500,000
SGB Homes	$3,200,000	$160,000	$480,000	$80,000	$80,000	$4,000,000
Residential Energy Assessments	***$350,000***	***$17,500***	***$105,000***	***$210,000***	***$17,500***	***$700,000***
Total Residential	**$7,400,000**	**$218,750**	**$915,000**	**$1,486,250**	**$180,000**	**$10,200,000**
Non-Residential						
Business Rebates	$1,100,000	$90,000	$225,000	$495,000	$90,000	$2,000,000
Custom Business Rebates	$39,000	$5,550	$27,750	$72,150	$5,550	$150,000
Business Energy Assessments	***$350,000***	***$17,500***	***$105,000***	***$175,000***	***$52,500***	***$700,000***
Distributed Generation	$1,200,000	$55,000	$220,000	$220,000	$55,000	$1,750,000
Total Non-Residential	**$2,689,000**	**$168,050**	**$577,750**	**$962,150**	**$203,050**	**$4,600,000**
Low-Income						
L-I Weatherization[1]	$373,500	$67,500	$9,000	$ -	$ -	$450,000
L-I Bill Assistance[2]	$ -	$ -	$ -	$ -	$ -	$200,000
Total Low-Income	**$373,500**	**$67,500**	**$9,000**	**$ -**	**$ -**	**$650,000**
Education						
Energy Education	***$ -***	***$ -***	***$550,000***	***$ -***	***$ -***	***$550,000***
Total Energy Efficiency	**$10,462,500**	**$454,300**	**$2,051,750**	**$2,448,400**	**$383,050**	**$16,000,000**
Renewable Energy Resource Technology						
Solar Thermal Rebates	***$350,000***	***$15,000***	***$60,000***	***$67,500***	***$7,500***	***$500,000***
Total Portfolio	**$10,812,500**	**$469,300**	**$2,111,750**	**$2,515,900**	**$390,550**	**$16,500,000**

[1] L-I Weatherization delivery and evaluation are performed by the Arizona Commerce Authority and community agencies and therefore, the associated costs are incorporated into the administration budget category.

[2] L-I Bill Assistance is not a rebate program and does not adhere to the above budget categories. Program administration is capped at $15,000.

The below summary is an excerpt from the filing was provided by Southwest to describe the individual programs in its Energy Efficiency and Renewable Energy Resource Technology Portfolio.

Summary of Programs

"*Smarter Greener Better Residential Rebates*: Rebates will be offered to residential customers on qualified program measures and mailed to participating customers upon proof-of-purchase and installation. The measures include: ENERGY STAR@ water and space heating measures, ENERGY STAR@ clothes washers and high efficiency natural gas clothes dryers, ENERGY STAR@ dishwashers, and smart low-flow showerheads. The program also offers rebates on weatherization measures such as insulation, duct sealing and high efficiency windows.

Smarter Greener Better Homes Rebates: will be offered to homebuilders who build ENERGY STAR@ certified homes and install ENERGY STAR' water and space heating measures, ENERGY STAR@ clothes washers and high efficiency natural gas clothes dryers and attic insulation. The program will be available to all builders of new single-family subdivision and custom homes and individually metered multi-family homes featuring natural gas water and space heating.

Smarter Greener Better Residential Energy Assessments (Pilot): Southwest Gas proposes a joint residential energy assessment (energy audit) program with APS, SRP and/or TEP. All three of these utilities serve in Southwest Gas' Arizona service territory and have already developed their own residential energy audit programs. For all participating homes with natural gas water and space heating, Southwest Gas will pay rebates to homeowners for a portion of contractor costs and will provide direct-install measures such as smart low-flow showerheads and lavatory faucet accessories (aerators) and information for the Southwest Gas *Smarter Greener Better Residential Rebates* program.

Smarter Greener Better Business Rebates: Rebates will be offered to nonresidential customers on qualified program measures and mailed to participating customers upon proof-of-purchase and installation. The measures include: high efficiency space and water heating units (including boilers and boiler tune-ups), clothes washers, a full suite of commercial kitchen high efficiency products (including dishwashers, natural gas fryers, griddles, steamers, conveyor, convection and combination ovens) and commercial weatherization measures.

Smarter Greener Better Custom Business Rebates: Rebates will be offered to non-residential customers based on achieved annual energy savings. The program does not specify eligible measures in order to provide participants maximum flexibility in identifying potential projects. Participants may propose any measure that produces a verifiable natural gas usage reduction, is installed in either existing or new construction applications, has a minimum useful life of seven years and exceeds minimum cost-effectiveness requirements. Qualifying measures include those that target cost-effective natural gas savings, such as retrofits of existing systems, improvements to existing systems and first time installations where the system's efficiency exceeds applicable codes or standard industry practice.

Smarter Greener Better Business Energy Assessments (Pilot): Rebates of up to $5,000 per non-residential customer will be provided to aid in offsetting the cost of conducting a comprehensive energy assessment (energy audit) for all, or a substantial portion of the customer's premises. The audit must meet or exceed the American Society of Heating, Refrigerating, and Air Conditioning Engineers (ASHRAE) Level 2, energy audit standards. The energy audit will study a customer's existing equipment and building envelope and identify potential energy conservation measures to reduce overall energy consumption and increase energy efficiency.

Smarter Greener Better Distributed Generation: The program provides rebates to non-residential customers to achieve significant fuel savings by promoting high efficiency electric generation, providing financial benefits during peak electrical demand periods, and demonstrating the use of new natural gas technologies that are being brought to market. The rebates are based upon the size and efficiency of the system being installed and range from $400 to $500 per kW.

Smarter Greener Better Low-Income Energy Conservation: The Low-Income Energy Conservation (LIEC) program provides income-qualified residential customers with money-saving weatherization measures that reduce energy use in their homes. The program will be available to households with annual incomes less than 150 percent of the federal poverty income guidelines, and will be administered by Southwest Gas in conjunction with the Arizona Commerce Authority (ACA - formerly dba Arizona Energy Office). The ACA manages the Department of Energy's (DOE) statewide Weatherization Assistance Program in Arizona and sub-contracts with local community agencies to install home weatherization measures. The home weatherization measures focus on four major categories: 1) duct repair; 2) infiltration control; 3) insulation (including attic, duct and floor); and 4) repair or replacement of appliances that are not operational or pose a health hazard.

Smarter Greener Better Energy Education (Pilot): The Energy Education program provides customers with energy efficiency and conservation information and recommendations to encourage the utilization of energy-efficient alternatives. In particular, the program focuses on specific energy efficiency or technology information that will help customers optimize natural gas usage. Print and radio mediums will be used to educate customers on the efficient use of natural gas and energy in general.

Smarter Greener Better Solar Thermal Rebates: Rebates will be offered to residential and non-residential customers on qualified solar thermal systems, used for water heating or pool heating, upon proof-of-purchase and installation. The program objective is to increase public awareness of the benefits of solar thermal systems and to reduce customer natural gas usage by providing economically beneficial rebates to install the systems. Long-term customer energy savings will be realized throughout the life of the solar thermal systems.

To be eligible for participation in any of Southwest Gas' EE and RET programs, all new and existing residential, non-residential and low-income customers must have active Southwest Gas accounts, and residences and facilities must be within Southwest Gas' Arizona service territory. In addition, customers must also contribute towards the funding of these programs through the DSM rate adjuster.

EXHIBIT 3. SOUTHWEST SAVINGS AND BENEFITS TABLE

Table 1 – Portfolio Annual and Lifetime Therm Savings; Lifetime Societal Benefits, Costs and Net Benefits; and Cost-Effectiveness

Program	Annual Therm Savings	Lifetime Therm Savings	Societal Benefits	Societal Costs	Net Benefits	Cost-Effectiveness Ratio
Residential						
Residential Rebates	640,000	12,800,000	$8,814,254	$6,783,333	$2,030,921	1.30
SGB Homes	570,000	15,960,000	$11,653,139	$5,066,667	$6,586,473	2.30
Residential Energy Assessments	19,000	190,000	$120,432	$1,050,000	$(929,568)	N/A[2]
Total Residential	**1,229,000**	**28,950,000**	**$20,587,825**	**$12,900,000**	**$7,687,825**	**1.60**
Non-Residential						
Business Rebates	580,000	8,700,000	$5,788,537	$2,733,333	$3,055,204	2.12
Custom Business Rebates	18,000	270,000	$179,644	$161,250	$18,394	1.11
Business Energy Assessments				$1,050,000	$(1,050,000)	N/A[2]
Distributed Generation	516,000	10,320,000	$7,106,492	$2,950,000	$4,156,492	2.41
Total Non-Residential	**1,114,000**	**19,290,000**	**$13,074,674**	**$6,894,583**	**$6,180,090**	**1.90**
Low-Income						
L-I Weatherization[1]	21,000	525,000	$374,859	$450,000	$(75,141)	0.83
Education						
Energy Education				$550,000	$(550,000)	N/A[2]
Total Energy Efficiency	**2,364,000**	**48,765,000**	**$34,037,358**	**$20,794,583**	**$13,242,774**	**1.64**
Solar Thermal						
Solar Thermal	87,000	1,479,000	$997,377	$616,667	$380,711	N/A[3]
Totals	**2,451,000**	**50,244,000**	**$35,034,735**	**$21,411,250**	**$13,623,485**	**1.64**

1L-I Bill Assistance is not included in this Table because there are no therm savings attributable to the program.
2Pursuant to Section R14-2-2512(G) of the Gas EE Standard, cost-effectiveness is not required for pilot programs.
3Pursuant to the Gas EE Standard, cost-effectiveness is not required for RET programs.

BEFORE THE ARIZONA CORPORATION COMMISSION

GARY PIERCE
Chairman
PAUL NEWMAN
Commissioner
SANDRA D. KENNEDY
Commissioner
BOB STUMP
Commissioner
BRENDA BURNS
Commissioner

IN THE MATTER OF THE APPLICATION OF SOUTHWEST GAS CORPORATION FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS PROPERTIES THROUGHOUT ARIZONA.	DOCKET NO. G-01551A-10-0458

DIRECT

TESTIMONY

OF

DAVID C. PARCELL

ON BEHALF OF

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JUNE 10, 2010

EXHIBIT
ALL-STATE LEGAL®
S-8

DAVID C. PARCELL
EXECUTIVE SUMMARY
SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-10-0458

My Direct Testimony provides my estimate of the cost of capital for Southwest Gas Corporation ("Southwest Gas"). My cost of capital recommendation is as follows:

	Percent	Cost	Return
Long-term Debt	47.70%	8.34%	3.98%
Common Equity	52.30%	9.0-10.5%	5.49%
Total Capital	100.00%		8.69-9.47%
			9.08% Mid-point

The only difference between my 9.08 percent recommendation and the 9.73 percent cost of capital request of Southwest Gas is the cost of common equity – I propose a cost of equity of 9.75 percent and Southwest Gas requests a cost of equity of 11.0 percent.

My 9.75 percent cost of common equity is derived from my application of three cost of equity models:

Discounted Flow	9.0-9.6%
Capital Asset Pricing Model	8.0-8.1%
Comparable Earnings	9.5-10.5%

In addition, my Direct Testimony addresses the Fair Value Rate of Return ("FVROR") which should be applied to the Fair Value Rate Base of Southwest Gas. I recommend two alternative FVROR values for Southwest Gas – a 6.69 percent value using a zero percent return on the Fair Value Increment (differential between Fair Value Rate Base and Original Cost Rate Base) and 7.02 percent value using a 1.25 percent inflation-adjusted risk-free return.

TABLE OF CONTENTS

EXHIBITS

ATTACHMENT

I. INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is David C. Parcell. I am President and Senior Economist of Technical Associates, Inc. My business address is 9030 Stony Point Parkway, Suite 580, Richmond, Virginia 23235.

Q. Please summarize your educational background and professional experience.

A. I hold B.A. (1969) and M.A. (1970) degrees in economics from Virginia Polytechnic Institute and State University (Virginia Tech) and a M.B.A. (1985) from Virginia Commonwealth University. I have been a consulting economist with Technical Associates since 1970. I have provided cost of capital testimony in public utility ratemaking proceedings dating back to 1972. In connection with this, I have previously filed testimony and/or testified in approximately 460 utility proceedings before some 50 regulatory agencies in the United States and Canada. Attachment 1 provides a more complete description of my education and relevant work experience.

Q. Have you previously testified before the Arizona Corporation Commission?

A. Yes, I have testified in a number of prior Arizona Corporation Commission ("Commission") proceedings, including the recent gas rate cases involving Southwest Gas Corporation (Docket No. G-01551A-07-0504), UNS Gas, Inc. (Docket Nos. G-04204A-05-0463 and G-04204A-08-0571), as well as electric rate cases involving Tucson Electric Power Co. (Docket No. E-01933A-07-0402 et al.), Arizona Public Service Company (Docket Nos. E-01345A-05-0816 and E-01345A-08-0172), and UNS Electric, Inc. (Docket Nos. E-04204A-06-0783 and E-04204A-09-0206). I have also testified in several water utility proceedings on behalf of the Utilities Division Staff.

Q. What is the purpose of your testimony in this proceeding?

A. I have been retained by the Utilities Division Staff to evaluate the cost of capital aspects of the current filing of Southwest Gas Corporation ("Southwest Gas" or "Company"). I have performed independent studies and am making recommendations on the current cost of capital for Southwest Gas. My testimony also responds to the Company's cost of capital proposals sponsored by Southwest Gas witness Robert B. Hevert.

Q. Have you prepared an exhibit in support of your testimony?

A. Yes, I have prepared one exhibit, identified as Schedule 1 through Schedule 14. This exhibit was prepared either by me or under my direction. The information contained in this exhibit is correct to the best of my knowledge and belief.

II. RECOMMENDATIONS AND SUMMARY

Q. What are your recommendations in this proceeding?

A. My overall cost of capital recommendations for Southwest Gas are:

	Percent	Cost	Return
Short-Term Debt	0.00%	N/A	N/A
Long-Term Debt	47.70%	8.34%	3.98%
Common Equity	52.30%	9.00-10.50%	4.71-5.49%
Total	100.00%		8.69-9.47%
			9.08% with 9.75% ROE

Southwest Gas' application requests a return on common equity of 11.0 percent and a total cost of capital of 9.73 percent.

Q. Please summarize your cost of capital analyses and related conclusions for Southwest Gas.

A. This proceeding is concerned with Southwest Gas' regulated natural gas utility operations in Arizona. My analyses are concerned with the Company's total cost of capital. The first step in performing these analyses is the development of the appropriate capital structure. Southwest Gas' proposed capital structure is the June 20, 2010 "Arizona" capital structure ratios of the Company, which reflects the actual capital structure of the Company and adjusts this for several issues of industrial development revenue bonds issued by localities in California and Nevada.

The second step in a cost of capital calculation is a determination of the embedded cost rate of long-term debt. I have used an 8.34 percent cost for long-term debt which is contained in Southwest Gas' application.

The third step in the cost of capital calculation is the estimation of the cost of common equity. I have employed three recognized methodologies to estimate the cost of equity for Southwest Gas. Each of these methodologies is applied to two groups of proxy gas utilities. These three methodologies and my findings are:

Methodology	Range
Discounted Cash Flow	9.0-9.6%
Capital Asset Pricing Model	7-9-8.0%
Comparable Earnings	9.5-10.5%

Based upon these findings, I conclude that the cost of common equity for the proxy utilities is within a range of 9.0 percent to 10.5 percent (9.75 percent mid-point). This range is determined by the results of two of my cost of equity methodology results (i.e., DCF and CE), since these two sets of results fall within this range. I recommend that

Southwest Gas' cost of equity be the mid-point of my 9.0 percent to 10.5 percent range or 9.75 percent.

Combining the capital structure and individual cost rates, results in a weighted cost of capital for Southwest Gas. My recommended overall cost of capital range is 8.69 percent to 9.47 percent (9.08 percent with 9.75 percent cost of equity). I recommend a 9.08 percent cost of capital for Southwest Gas.

III. ECONOMIC PRINCIPLES AND METHODOLOGIES

Q. What are the primary economic principles that establish the standards for determining a fair rate of return for a regulated utility?

A. Public utility rates are normally established in a manner designed to allow the recovery of their costs, including capital costs. This is frequently referred to as "cost of service" ratemaking. Rates for regulated public utilities traditionally have been primarily established using the "rate base - rate of return" concept. Under this method, utilities are allowed to recover a level of operating expenses, taxes, and depreciation deemed reasonable for rate-setting purposes, and are granted an opportunity to earn a fair rate of return on the assets utilized (i.e., rate base) in providing service to their customers.

The rate base is derived from the asset side of the utility's balance sheet as a dollar amount and the rate of return is developed from the liabilities/owners' equity side of the balance sheet as a percentage. Thus, revenue impact of the cost of capital is derived by multiplying the rate base by the rate of return, including income taxes.

The rate of return is developed from the cost of capital, which is estimated by weighting the capital structure components (i.e., debt, preferred stock, and common equity) by their percentages in the capital structure and multiplying these values by their cost rates. This is also known as the weighted cost of capital.

Technically, "fair rate of return" is a legal and accounting concept that refers to an ex post (after the fact) earned return on an asset base, while the cost of capital is an economic and financial concept which refers to an ex ante (before the fact) expected or required return on a liability base. In regulatory proceedings, however, the two terms are often used interchangeably. I have equated the two concepts in my testimony.

From an economic standpoint, a fair rate of return is normally interpreted to mean that an efficient and economically managed utility will be able to maintain its financial integrity, attract capital, and establish comparable returns for similar risk investments. These concepts are derived from economic and financial theory and are generally implemented using financial models and economic concepts.

From a legal perspective, while I am not a lawyer, it is my understanding that two United States Supreme Court decisions provide the controlling standards for a fair rate of return. The first decision is Bluefield Water Works and Improvement Co. v. Public Serv. Comm'n of West Virginia, 262 U.S. 679 (1923). In this decision, the Court stated:

> *What annual rate will constitute **just compensation** depends upon many circumstances and must be **determined by** the **exercise of fair and enlightened judgment**, having regard to all relevant facts. A **public utility** is entitled to such rates as will permit it to **earn a return** on the value of the property which it employs for the convenience of the public equal to that **generally being made** at the same time and in the same general part of the country on **investments in other business undertakings** which are **attended by corresponding risks and uncertainties**; but it has no **constitutional right to profits** such as are realized or anticipated in **highly profitable enterprises or speculative ventures**. The **return** should be reasonably*

> *sufficient to assure confidence in the* ***financial soundness*** *of the utility, and should be adequate,* ***under efficient and economical management****, to maintain and* ***support its credit*** *and* ***enable it to raise the money*** *necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time, and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally.* **[Emphasis added.]**

Thus, the Bluefield decision, in my opinion as a non-lawyer, established the following standards for a fair rate of return: comparable earnings, financial integrity, and capital attraction. It also noted the changing level of required returns over time as well as an underlying assumption that the utility be operated in an efficient manner.

The second decision is Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1942). In that decision, the Court stated:

> *The rate-making process under the [Natural Gas] Act, i.e., the fixing of 'just and reasonable' rates, involves a* ***balancing*** *of the* ***investor*** *and* ***consumer interests*** *. . . . From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the* ***return*** *to the equity* ***owner*** *should be* ***commensurate*** *with* ***returns*** *on* ***investments*** *in* ***other enterprises having corresponding risks****. That return, moreover, should be sufficient to assure confidence in the* ***financial integrity*** *of the enterprise, so as to* ***maintain its credit*** *and to* ***attract capital****.* **[Emphasis added.]**

The three economic and financial parameters in the Bluefield and Hope decisions - comparable earnings, financial integrity, and capital attraction - reflect the economic criteria encompassed in the "opportunity cost" principle of economics. The opportunity cost principle provides that a utility and its investors should be afforded an opportunity (not a guarantee) to earn a return commensurate with returns they could expect to achieve on investments of similar risk. The opportunity cost principle is consistent with the fundamental premise on which regulation rests; namely, that it is intended to act as a surrogate for competition.

I understand that because Arizona is a "Fair Value" state, Hope and Bluefield do not set forth the legal requirements applicable to determining fair rate of return in Arizona. In Simms v. Round Valley Light & Power Company,[1] the Arizona Supreme Court took exception to application of the following principle in Arizona since the Constitution mandates consideration of fair value:

> *"In the Hope case the court, in testing the reasonableness of rates fixed by the Federal Power Commission under the Natural Gas Act, 15 U.S.C.A. Section 717 et seq., after holding that congress had provided no formula by which just and reasonable rates were to be determined, ruled that it was the final result reached and not the method used in reaching the result that was controlling and that it was unimportant to 'determine the various permissible ways in which any rate base on which the return is computed might be arrived at."*

My testimony does not advocate that the Commission ignore the *Simms* holding in this regard, or the fair value of Southwest Gas' property, which it is required to consider under Article 15, Section of the Arizona Constitution. Rather, I find the Hope and Bluefield decisions to be helpful in their discussion of comparable earnings, financial integrity and capital attraction. I note that Southwest Gas witness Hevert also cites the Hope and Bluefield cases as "guidelines" for evaluating the cost of capital for the Company. *See* Hevert Direct at pages 3-5.

[1] 294 P.2d 378 (1956).

Q. How can these parameters be employed to estimate the cost of capital for a utility?

A. Neither the courts nor economic/financial theory have developed exact and mechanical procedures for precisely determining the cost of capital. This is the case because the cost of capital is an opportunity cost and is prospective-looking, which dictates that it must be estimated.

There are several useful models that can be employed to assist in estimating the cost of equity capital, which is the capital structure item that is the most difficult to determine. These include the discounted cash flow ("DCF"), capital asset pricing model ("CAPM"), comparable earnings ("CE") and risk premium ("RP") methods. Each of these methods (or models) differs from the others and each, if properly employed, can be a useful tool in estimating the cost of common equity for a regulated utility. Many state regulatory commissions reply upon the DCF and CAPM models to develop the cost of common equity for utilities.

Q. What methods did you use to determine its cost of common equity?

A. I utilized three methodologies to determine Southwest Gas' cost of common equity: the DCF, CAPM, and CE methods. I have not employed a RP model in my analyses although, as discussed later, my CAPM analysis is a form of the RP methodology. Each of these methodologies will be described in more detail in my testimony that follows.

Q. What methods did the Company use?

A. Mr. Hevert used the DCF, CAPM and RP methods which I discuss later in my testimony.

IV. GENERAL ECONOMIC CONDITIONS

Q. Are economic and financial conditions important in determining the cost of capital for Southwest Gas?

A. Yes. The costs of capital for both fixed-cost (debt and preferred stock) components and for common equity are determined, in part, by current and prospective economic and financial conditions. At any given time, each of the following has an influence on the costs of capital:

- the level of economic activity (*i.e.,* growth rate of the economy);
- the stage of the business cycle *(i.e.,* recession, expansion, or transition);
- the level of inflation; and
- expected economic conditions.

My understanding is that this position is consistent with the *Bluefield* decision, in which the Court noted: "[a] rate of return may be reasonable at one time, and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally." Bluefield, 262 U.S. at 679.

Q. What indicators of economic and financial activity have you evaluated in your analyses?

A. I examine several sets of economic statistics from 1975 to the present. I chose this time period because it permits the evaluation of economic conditions over four full prior business cycles, including the most recent cycle, allowing for an assessment of changes in long-term trends. This period also approximates the beginning and the continuation of active rate case activities by public utilities.

A business cycle is commonly defined as a complete period of expansion (recovery and growth) and contraction (recession). A full business cycle is a useful and convenient period over which to measure levels and trends in long-term capital costs because it incorporates the cyclical influences (*i.e.,* stage of business cycle) and thus permits a comparison of structural (or long-term) trends.

Q. Please describe the timeframe of the four prior business cycles.

A. The four prior complete cycles cover the following periods:

Business Cycle	Expansion Cycle	Contraction Period
1975-1982	Mar. 1975-July 1981	Aug. 1981-Oct. 1982
1982-1991	Nov. 1982-July 1990	Aug. 1990-Mar. 1991
1991-2001	Apr. 1991-Mar. 2001	Apr. 2001-Nov. 2001
2001-2009	Dec. 2001-Nov. 2007	Dec. 2007-June. 2009

Source: National Bureau of Economic Research, "Business Cycle Expansions and Contractions."

Q. Do you have any general observations concerning the recent trends in economic conditions and their impact on capital costs over this broad period?

A. Yes, I do. As I will describe below, until the end of 2007, the United States economy had enjoyed general prosperity and stability since the early 1980s. This period had been characterized by longer economic expansions, relatively tame contractions, relatively low and declining inflation, and declining interest rates and other capital costs.

However, over the past four years, the economy has declined significantly, initially as a result of the 2007 collapse of the "sub-prime" mortgage market and the related liquidity crisis in the financial sector of the economy. Subsequently, this financial crisis intensified with a more broad-based decline, initially based on a substantial increase in petroleum prices and a dramatic decline in the U.S. financial sector, culminating with the collapse and/or bailouts of a significant number of venerable institutions such as Bear Stearns, Lehman Brothers, Merrill Lynch, Freddie Mac, Fannie Mae, AIG and Wachovia. The recession also witnessed the demise of national entities, such as Circuit City, and the declared bankruptcy of automotive manufacturers, such as Chrysler and General Motors.

This decline has been described as the worst financial crisis since the Great Depression and has been referred to as the "Great Recession." The United States and other governments have been and continue to implement unprecedented actions to attempt to correct or minimize its scope and effects.

It appears that the recession reached its low point in mid-2009 and that the economy has since begun to expand again, although at a slow and uneven rate. However, the length and severity of the recession, as well as a relatively slow recovery, indicate that the impacts of the recession have been and will be felt for an extended period of time. As an example of this, both the U.S. and Arizona unemployment rates still stand at about 9 percent - near the highest rates in decades.

Q. Please describe recent and current economic and financial conditions and their impact on the costs of capital.

A. Schedule 2 shows several sets of relevant economic data for the cited time period. Pages 1 and 2 contain general macroeconomic statistics; pages 3 and 4 show interest rates; and pages 5 and 6 contain equity market statistics.

Pages 1 and 2 show that the United States economy ended 2007 as the sixth year of an economic expansion but, as I previously noted, it subsequently entered a significant decline. This is indicated by the growth in real (*i.e.,* adjusted for inflation) Gross

Domestic Product ("GDP"), industrial production, and the increase in the unemployment rate.

The rate of inflation is also shown on pages 1 and 2. As is reflected in the Consumer Price Index ("CPI"), for example, inflation rose significantly during the 1975-1982 business cycle and reached double-digit levels in 1979-1980. The rate of inflation declined substantially in 1981, and remained at or below 6.1 percent during the 1983-1991 business cycle. Since 1991, the CPI has been 4.1 percent or lower. The 0.1 percent rate of inflation in 2008, the 2.7 percent level in 2009, and the 1.5 percent level in 2010 were among the lowest levels of the past 30 years. This is indicative of virtually no inflation, which is reflective of lower capital costs.

Q. What have been the trends in interest rates over the four business cycles (1975-2010)?

A. Pages 3 and 4 show several series of interest rates. Rates rose sharply to record levels in 1975-1981 when the inflation rate was high and generally rising. Interest rates declined substantially in conjunction with inflation rates during the remainder of the 1980s and throughout the 1990s. Interest rates declined even further from 2000-2005 and generally recorded their then-lowest levels since the 1960s.

Most recently, the Federal Reserve has lowered the Federal Funds rate (i.e., short-term rate) on several occasions; currently it is 0.25%, an all-time low. In 2008, there was a pronounced decline in short-term rates and long-term U.S. Treasury Securities yields, and an increase in corporate bond yields, reflecting the "flight to safety," wherein there was a reluctance of investors to purchase common stocks and corporate bonds while concomitantly moving their money into very safe government bonds. Since then, as seen on page 3, bond yields have declined to their lowest levels in the past four business cycles and in more than 35 years, with lending rates remaining at historically low levels.

Q. What does Schedule 2 show for the trends in common share prices?

A. Pages 5 and 6 show several series of common stock prices and ratios. These indicate that share prices were essentially stagnant during the high inflation/high interest rate environment of the late 1970s and early 1980s. The 1983-1991 business cycle and the more recent cycles witnessed a significant upward trend in stock prices. The beginning of the current financial crisis saw stock prices decline precipitously. Stock prices in 2008 and early 2009 were down significantly from 2007 levels, reflecting the financial/economic crises. Beginning in the second quarter of 2009, prices have recovered somewhat but still remain well below the levels prevailing prior to the current recession.

Q. What conclusions should the Commission draw from your discussion of economic and financial conditions depicted in your data?

A. It is apparent that recent economic and financial circumstances have been radically different from any that have prevailed since at least the 1930s. The late 2008-early 2009 deterioration in stock prices, the decline in U.S. Treasury bond yields, and the increase in corporate bond yields are evidenced in the recent "flight to safety." On the other side of this "flight to safety" is the negative perception of the recent decline, which has significantly reduced the value of most retirement accounts, investment portfolios and other assets. One significant aspect of this has been a decline in investor expectations of returns, including stock returns. Finally, as noted above, interest rates currently are at levels below those prevailing prior to the financial crisis of late 2008-early 2009 and are near the lowest level in the past 35 years. This "flight to safety" does not represent an increase in the cost of capital; rather, it more properly reflects an "availability of capital" since investors were unwilling to invest in many assets other than U.S. Treasury bonds. Further reflecting a decreased cost of capital, utility bond rates are at their lowest levels in the past four business cycles.

V. SOUTHWEST GAS' OPERATIONS AND RISKS

Q. Please summarize Southwest Gas and its operations.

A. Southwest Gas is an operating gas distribution company. The Company is engaged in the business of purchasing, transporting and distributing natural gas to residential, commercial, and industrial customers in geographically diverse portions of Arizona, Nevada and California. Southwest Gas is the largest distributor of natural gas in both Arizona and Nevada. Southwest Gas also owns Paiute Pipeline Co., as well as NPL Construction Company. Until 1996, Southwest Gas owned PriMerit Bank (formerly Nevada Savings and Loan).

Q. What are the current security ratings of Southwest Gas?

A. As is shown on Schedule 3, the current bond ratings of Southwest Gas are:

Moody's	Baa2
Standard & Poor's	BBB
Fitch	BBB

As this indicates, Southwest Gas' bonds presently carry triple B ratings by the three rating agencies who rate the Company's debt.

Q. What has been the trend in Southwest Gas' debt ratings?

A. This is also depicted on Schedule 3. As this Schedule indicates, the Company's debt ratings were raised by S&P in 2009 and by Moody's in 2010.

Q. How have the rating agencies recently described Southwest Gas?

A. An example of this is provided in a May 27, 2010 report on Southwest Gas by Moody's, wherein Company's ratings were raised. In this report, Moody's stated:

> *New York, May 27, 2010 -- Moody's Investors Services upgraded the senior unsecured rating of Southwest Gas Corporation (Southwest) to Baa2 from Baa3. The rating outlook is stable.*
>
> *"The upgrade follows improvements in Southwest's cash flow credit metrics which we believe will be sustained for the foreseeable future," said Kevin Rose, Vice President & Senior Analysts. "Even in the face of an economic downturn in Southwest's primary service territories, financial results for 2009 were generally robust", Rose added. The improvement comes primarily as a result of recent rate relief in all of Southwest's regulatory jurisdictions, and the company's continued effort to minimize costs.*
>
> . . .
>
> *The rating upgrade also recognizes signs of improvements in Southwest's regulatory environment where we remain cautiously optimistic about, primarily in Nevada (34% of operating margins) and potentially Arizona (55% of operating margins). In Nevada, the Public Utilities Commission of Nevada approved the company's request for the implementation of decoupling mechanism in its April 2009 general rate case, pursuant to the decoupling legislation approved in 2008. Furthermore, the Arizona Corporation Commission (ACC) has conducted a series of workshops in 2009 and 2010 to evaluate the possibility of implementing a decoupling mechanism in Arizona, and is currently reviewing related proposals submitted by utilities in its jurisdiction, including Southwest. The final ACC decision is expected sometime later this year.*

Q. As noted by Moody's, Southwest Gas is requesting certain regulatory cost-recovery mechanisms in this proceeding. What are the cost of capital implications of the implementation of these?

A. It is my understanding that the Company is requesting approval to implement certain new rate design proposals that, if approved, will be risk-reducing. These proposals include an Energy Efficiency Enabling Provision ("EEP"), which provides for full revenue decoupling for all of Southwest Gas' customers except for its largest general service customers.

Q. How are these proposals risk-reducing to the Company?

A. These rate design proposals, if approved, are risk-reducing to Southwest Gas since the Company's revenues, and income, will be essentially insulated from variations due to weather and usage. The net effect of these proposals is to transfer a significant portion of the Company's risks from its shareholders to its ratepayers.

Q. Is the Staff recommending approval of these new proposals which would transfer significantly more risk to ratepayers?

A. Other Staff witnesses are addressing the Company's new risk-reducing rate design proposals. It is my understanding that the Staff is recommending a different proposal. However, I want to point out that if the Commission should adopt either of them, it would reduce the Company's risk, normally a consideration in the cost of equity estimation.

Q. Are you proposing an adjustment to Southwest Gas' cost of equity if either of the proposed decoupling mechanisms is approved?

A. No, I am not proposing an adjustment if decoupling is approved for Southwest Gas. I have made such recommendations in other rate proceedings based upon the reduction in risk associated with decoupling. However, in this proceeding I am not making such a recommendation. This is the case because the Commission has indicated in its *Final ACC Policy Statement Regarding Utility Disincentives to Energy Efficiency and Decoupled Rate Structures, Docket Nos. E-00000J-08-0314 and G-00000C-08-0314* that decoupling should be implemented for an initial three-year period and that more detailed evaluations of its impact, including cost of capital implications, be conducted at the end of the three year period.

VI. CAPITAL STRUCTURE AND COST OF DEBT

Q. What is the importance of determining a proper capital structure in a regulatory framework?

A. A utility's capital structure is important because the concept of rate base – rate of return regulation requires that a utility's capital structure be determined and utilized in estimating the total cost of capital. Within this framework, it is proper to ascertain whether the utility's capital structure is appropriate relative to its level of business risk and relative to other utilities.

As discussed in Section III of my testimony, the purpose of determining the proper capital structure for a utility is to help ascertain its capital costs. The rate base – rate of return concept recognizes the assets employed in providing utility services and provides for a return on these assets by identifying the liabilities and common equity (and their cost rates) used to finance the assets. The inherent assumption in this procedure is that the dollar values of the capital structure and the rate base are approximately equal and the former is utilized to finance the latter.

The common equity ratio (i.e., the percentage of common equity in the capital structure) is the capital structure item which normally receives the most attention. This occurs because common equity: (1) usually commands the highest cost rate; (2) generates associated income tax liabilities; and, (3) causes the most controversy since its cost cannot be precisely determined.

Q. How have you evaluated the capital structure of Southwest Gas?

A. I first examined the 1995-2010 capital structure ratios of Southwest Gas. Schedule 4 shows the historic capital structure ratios of the Company. The respective common equity ratios over the past five years are as follows:

	Inc'l S-T Debt	Exc'l S-T Debt
2006	38.9%	38.9%
2007	41.0%	41.2%
2008	43.5%	44.5%
2009	46.4%	46.4%
2010	49.3%	50.9%

This indicates a significantly rising common equity ratio over this period. In fact, the most current common equity ratios exceed the levels of five years ago by over 10 percentage points. Also shown on Schedule 4 are the Company's common equity ratios going back to 1995. As this indicates, Southwest Gas maintained a very low equity ratio (i.e., 30 percent to 35 percent) until about 2006. This significant increase in the Company's equity ratio is indicative of a decline in financial risk.

Q. How do these capital structure ratios compare to the gas distribution utility industry?

A. I have prepared Schedule 5 to make this comparison. Page 1 of this schedule shows the 2006-2010 capital structure ratios of the Value Line group of LDC's, excluding short-term debt. Page 2 of Schedule 5 indicates the 2006-2010 capital structure ratios for this group, including short-term debt. The average ratios are:

	Inc'l S-T Debt	Exc'l S-T Debt
2006	47%	50.5%
2007	46%	52.2%
2008	45%	53.8%
2009	49%	54.7%
2010	49%	57.7%

These common equity ratios (including short-term debt) are similar to those of the most recent Southwest Gas ratios.

Q. What capital structure ratios has Southwest Gas requested in this proceeding?

A. The Company requests use of the following capital structure:

Capital Item	Percent
Long-Term Debt	47.7%
Short-Term debt	0.0%
Common Equity	52.3%

This reflects the Company's actual capital structure as of June 30, 2010, adjusted to remove certain industrial development bonds issued in Nevada and California.

Q. What is the recent history of the Company's capital structure request?

A. In Decision No. 68487 (February 23, 3006), this Commission approved use of a hypothetical capital structure for the Company that contained 55 percent long-term debt, 5 percent preferred stock, and 40 percent common equity. This 40 percent common equity ratio exceeded the actual test period equity ratio and was apparently intended to be an "incentive" for the Company to raise its actual equity ratio. As stated by Mr. Wood in the most recent rate proceeding (Docket No. G-01551A-07-0504), in its Decision in the 2004 proceeding, the Commission directed the Company to submit a "recapitalization plan" explaining how it intended to achieve an actual 40 percent common equity ratio.

In the most recent case (Docket No. G-01551A-07-0504), the Company again requested a hypothetical capital structure, with an even higher common equity ratio, at 45 percent. In that proceeding, Southwest Gas witness Wood described this as a "target" common equity ratio and he indicated (page 9) "it is reasonable to assume that the Company will achieve 45 percent common equity ratio...." In that proceeding, the Commission did not adopt Southwest Gas' proposed hypothetical capital structure (with 45 percent common equity) but rather used the Company's actual capital structure (with 43.44 percent common equity).

Q. Has the Company raised its equity ratio since the last case?

A. Yes, it has. The actual test period capital structure of the Company contains some 52.3 percent common equity. It should be recognized that this reflects a reduction in the financial risk faced by Southwest Gas.

Q. What capital structure have you used in your analyses?

A. I have utilized the adjusted test period capital structure of the Company in my analyses. These are shown on my Schedule 1. I note that I normally include short-term debt in my cost of capital calculations and I understand that this Commission also uses short-term debt. However, in this case, it appears that Southwest Gas did not have any short-term debt at the end of the test period, so I did not include any in the capital structure.

Q. What cost rate of long-term debt have you used in your analysis?

A. I have utilized the 8.34 percent cost of long-term debt shown in the Company's filing.

Q. Can the cost of common equity be determined with the same degree of precision as the cost of debt?

A. No. The cost rate of debt is largely determined by interest payments, issue prices, and related expenses. The cost of common equity, on the other hand, cannot be precisely quantified, primarily because this cost is an opportunity cost. As discussed earlier, there are, however, several models which can be employed to estimate the cost of common equity. Three of the primary methods - DCF, CAPM, and CE - are developed in the following sections of my testimony.

VII. SELECTION OF PROXY GROUPS

Q. How have you estimated the cost of common equity for Southwest Gas?

A. Southwest Gas is a publicly-traded company. Consequently, it is possible to directly apply cost of equity models to this entity. However, it is customary to analyze groups of comparison or "proxy" companies as a substitute for Southwest Gas to determine its cost of common equity. I have developed such a proxy group for comparison to Southwest

Gas. I note that Southwest Gas witness Hevert has used a set of proxy companies in his cost of equity analysis.

My group of proxy companies is derived from the group of gas distribution companies followed by Value Line. Schedule 6 shows the criteria used to select my proxy group. The following criteria were employed for each company's selection in my proxy group:

(1) Inclusion in Value Line Natural Gas Utility Group;
(2) Currently pays dividends;
(3) Percent regulated gas revenues of 50 percent or greater;
(4) S&P and/or Moody's bond ratings of Triple-B or greater;
(5) Common equity ratio of about 40 percent to 60 percent; and,
(6) Value Line Safety of 1, 2, or 3.

Of the gas distribution companies followed by Value Line, nine companies meet these criteria. However, one of these – Nicor, is being acquired by AGL Resources. As a result, I have not included the former company in my proxy group. This group, which reflects a representative sample of local distribution companies ("LDCs"), is a proper proxy for Southwest Gas.

I have also considered the group of nine natural gas utilities that Southwest Gas witness Hevert utilized in his testimony. These are similar to the group of eight proxy companies I utilize. However, he includes New Jersey Resources and Nicor in his group and does not include Southwest Gas.

I note that, by developing my own group of proxy companies, used in conjunction with the groups of proxy companies utilized by Southwest Gas witness Hevert, I have given consideration to the Company's view as to the appropriate composition of the proxy companies for Southwest Gas.

VIII. DISCOUNTED CASH FLOW ANALYSIS

Q. What is the theory and methodological basis of the discounted cash flow model?

A. The DCF model is one of the oldest, as well as the most commonly-used, models for estimating the cost of common equity for public utilities. The DCF model is based on the "dividend discount model" of financial theory, which maintains that the value (price) of any security or commodity is the discounted present value of all future cash flows.

The most common variant of the DCF model assumes that dividends are expected to grow at a constant rate. This variant of the dividend discount model is known as the constant growth or Gordon DCF model. In this framework cost of capital is derived by the following formula:

$$K = \frac{D}{P} + g$$

where: K = discount rate (cost of capital)

P = current price

D = current dividend rate

g = constant rate of expected growth

This formula essentially recognizes that the return expected or required by investors is comprised of two factors: the dividend yield (current income) and expected growth in dividends (future income).

Q. Please explain how you have employed the DCF model.

A. I have utilized the constant growth DCF model. In doing so, I have combined the current dividend yield for each group of proxy utility stocks described in the previous section with several indicators of expected dividend growth.

Q. How did you derive the dividend yield component of the DCF equation?

A. There are several methods that can be used for calculating the dividend yield component. These methods generally differ in the manner in which the dividend rate is employed; i.e., current versus future dividends or annual versus quarterly compounding of dividends. I believe the most appropriate dividend yield component is the version listed below:

$$Yield = \frac{D_0(1+0.5g)}{P_0}$$

This dividend yield component recognizes the timing of dividend payments and dividend increases.

The P_0 in my yield calculation is the average (of high and low) stock price for each proxy company for the most recent three month period (February - April, 2010). The D_0 is the current annualized dividend rate for each proxy company.

Q. How have you estimated the dividend growth component of the DCF equation?

A. The dividend growth rate component of the DCF model is usually the most crucial and controversial element involved in this methodology. The objective of estimating the dividend growth component is to reflect the growth expected by investors that is embodied in the price (and yield) of a company's stock. As such, it is important to recognize that individual investors have different expectations and consider alternative indicators in deriving their expectations. This is evidenced by the fact that every investment decision resulting in the purchase of a particular stock is matched by another investment decision to sell that stock. Obviously, since two investors reach different decisions at the same market price, their expectations differ.

A wide array of indicators exist for estimating the growth expectations of investors. As a result, it is evident that no single indicator of growth is always used by all investors. It therefore is necessary to consider alternative indicators of dividend growth in deriving the growth component of the DCF model.

I have considered five indicators of growth in my DCF analyses. These are:

1. 2006-2010 (5-year average) earnings retention, or fundamental growth (per Value Line);
2. 5-year average of historic growth in earnings per share ("EPS"), dividends per share ("DPS"), and book value per share ("BVPS") (per Value Line);
3. 2011, 2012, and 2014-2016 projections of earnings retention growth (per Value Line);
4. 2008-2010 to 2014-2016 projections of EPS, DPS, and BVPS (per Value Line); and,

5. 5-year projections of EPS growth as reported in First Call (per Yahoo! Finance).

I believe this combination of growth indicators is a representative and appropriate set with which to begin the process of estimating investor expectations of dividend growth for the groups of proxy companies. I also believe that these growth indicators reflect the types of information that investors consider in making their investment decisions. As I indicated previously, investors have an array of information available to them, all of which should be expected to have some impact on their decision-making process.

Q. Please describe your DCF calculations.

A. Schedule 7 presents my DCF analysis. Page 1 shows the calculation of the "raw" (i.e., prior to adjustment for growth) dividend yield for each proxy company. Pages 2 and 3 of this schedule show the growth rate for the two groups of proxy companies. Page 4 shows the "raw" DCF calculations, which are presented on several bases: mean, median, and high values. These results can be summarized as follows:

	Mean	Median	Mean Low[2]	Mean High[3]	Mean Low[2]	Median High[3]
Proxy Group	8.5%	8.0%	8.2%	9.0%	7.8%	9.0%
Hevert Group	8.4%	8.2%	7.5%	9.3%	7.5%	9.6%

I note that the individual DCF calculations shown on Schedule 7 should not be interpreted to reflect the expected cost of capital for the proxy groups; rather, the individual values shown should be interpreted as alternative information considered by investors.

[2] Using only the lowest growth rate.
[3] Using only the highest growth rate.

The DCF results in Schedule 7 indicate average (mean and median) DCF cost rates of 8.0 percent to 8.5 percent. The highest DCF rates (i.e., using the highest growth rates only) are 9.0 percent to 9.6 percent.

Q. What do you conclude from your DCF analyses?

A. These analyses reflect a broad DCF range of 8.0 percent to 9.6 percent for the proxy groups. I believe that 9.0 percent to 9.6 percent reflects the proper DCF cost for the proxy groups at this time. I give less weight to the lower end and the mean/median results. I focus on the higher end of the DCF results because it is apparent that current DCF results for gas distribution companies are low by historic stands. Nevertheless, my DCF conclusion is well within the range of results.

IX. CAPITAL ASSET PRICING MODEL ANALYSIS

Q. Please describe the theory and methodological basis of the capital asset pricing model.

A. The CAPM is a version of the risk premium method. The CAPM describes and measures the relationship between a security's investment risk and its market rate of return. The CAPM was developed in the 1960s and 1970s as an extension of modern portfolio theory ("MPT"), which studies the relationships among risk, diversification, and expected returns.

Q. How is the CAPM derived?

A. The general form of the CAPM is:

$$K = R_f + \beta(R_m - R_f)$$

where: K = cost of equity

R_f = risk free rate

Rm = return on market

β = beta

Rm-R_f = market risk premium

As noted previously, the CAPM is a variant of the risk premium method. I believe the CAPM is generally superior to the simple risk premium method because the CAPM specifically recognizes the risk of a particular company or industry (i.e., beta), whereas the simple risk premium method assumes the same risk premium for all companies exhibiting similar bond ratings.

Q. What groups of companies have you utilized to perform your CAPM analyses?

A. I have performed CAPM analyses for the same groups of proxy utilities evaluated in my DCF analyses.

Q. What rate did you use for the risk-free rate?

A. The first term of the CAPM is the risk-free rate (R_f). The risk-free rate reflects the level of return that can be achieved without accepting any market risk.

In CAPM applications, the risk-free rate is generally recognized by use of U.S. Treasury securities. Two general types of U.S. Treasury securities are often utilized as the R_f component - short-term U.S. Treasury bills and long-term U.S. Treasury bonds.

I have performed CAPM calculations using the three month average yield (February – April, 2010) for 20-year U.S. Treasury bonds. Over this three month period, these bonds had an average yield of 4.32 percent.

Q. What is beta and what betas did you employ in your CAPM?

A. Beta is a measure of the relative volatility (and thus risk) of a particular stock in relation to the overall market. Betas of less than 1.0 are considered less risky than the market, whereas betas greater than 1.0 are more risky. Utility stocks traditionally have had betas below 1.0. I utilized the most recent Value Line betas for each company in the groups of proxy utilities.

Q. How did you estimate the market risk premium component?

A. The market risk premium component (R_m-R_f) represents the investor-expected premium of common stocks over the risk-free rate, or government bonds. For the purpose of estimating the market risk premium, I considered alternative measures of returns of the S&P 500 (a broad-based group of large U.S. companies) and 20-year U.S. Treasury bonds.

First, I have compared the actual annual returns on equity of the S&P 500 with the actual annual yields of U.S. Treasury bonds. Schedule 8 shows the return on equity for the S&P 500 group for the period 1978-2009 (all available years reported by S&P). This schedule also indicates the annual yields on 20-year U.S. Treasury bonds, as well as the annual differentials (i.e., risk premiums) between the S&P 500 and U.S. Treasury 20-year bonds. Based upon these returns, I conclude that this version of the risk premium is about 6.2 percent.

I have also considered the total returns (i.e., dividends/interest plus capital gains/losses) for the S&P 500 group as well as for the long-term government bonds, as tabulated by Ibbotson Associates, using both arithmetic and geometric means. I have considered the total returns for the entire 1926-2010 period, which are as follows:

	S&P 500	L-T Gov't Bonds	Risk Premium
Arithmetic	11.9%	5.9%	6.0%
Geometric	9.9%	5.5%	4.4%

I conclude from this that the expected risk premium is about 5.54 percent (i.e., average of all three risk premiums). I believe that a combination of arithmetic and geometric means is appropriate because investors have access to both types of means and, presumably, both types are reflected in investment decisions and thus stock prices and cost of capital.

Schedule 9 shows my CAPM calculations. The results are:

	Mean	Median
Proxy Group	8.0%	7.9%
Hevert Group	8.0%	7.9%

Q. What is your conclusion concerning the CAPM cost of equity?

A. The CAPM results collectively indicate a cost of about 8.0 percent for the two groups of proxy utilities.

X. COMPARABLE EARNINGS ANALYSIS

Q. Please describe the basis of the CE methodology.

A. The CE method is derived from the "corresponding risk" standard of the Bluefield and Hope cases. This method is thus based upon the economic concept of opportunity cost.

As previously noted, the cost of capital is an opportunity cost: the prospective return available to investors from alternative investments of similar risk.

The CE method is designed to measure the returns expected to be earned on the original cost book value of similar risk enterprises. Thus, this method provides a direct measure of the fair return, because the CE method translates into practice the competitive principle underlying regulation.

The CE method normally examines the experienced and/or projected returns on book common equity. The logic for examining returns on book equity follows from the use of original cost rate base regulation for public utilities, which uses a utility's book common equity to determine the cost of capital. This cost of capital is, in turn, used as the fair rate of return which is then applied (multiplied) to the book value of rate base to establish the dollar level of capital costs to be recovered by the utility. This technique is consistent with the rate base methodology generally used to set utility rates.

Q. How have you employed the CE methodology in your analysis of Southwest Gas' common equity cost?

A. I conducted the CE methodology by examining realized returns on equity for several groups of companies and evaluating the investor acceptance of these returns by reference to the resulting market-to-book ratios. In this manner, it is possible to assess the degree to which a given level of return equates to the cost of capital. It is generally recognized for utilities that market-to-book ratios of greater than one (i.e., 100%) reflect a situation where a company is able to attract new equity capital without dilution (i.e., above book value). As a result, one objective of a fair cost of equity is the maintenance of stock prices above book value.

I would further note that the CE analysis, as I have employed it, is based upon market data (through the use of market-to-book ratios) and is thus essentially a market test. As a result, my analysis is not subject to the criticisms occasionally made by some who maintain that past earned returns do not represent the cost of capital. In addition, my analysis uses prospective returns and thus is not confined to historical data.

Q. What time periods have you examined in your CE analysis?

A. My CE analysis considers the experienced equity returns of the proxy groups of utilities for the period 1992-2010 (i.e., past nineteen years). The CE analysis requires that I examine a relatively long period of time in order to determine trends in earnings over at least a full business cycle. Further, in estimating a fair level of return for a future period, it is important to examine earnings over a diverse period of time in order to avoid any undue influence from unusual or abnormal conditions that may occur in a single year or shorter period. Therefore, in forming my judgment of the current cost of equity I have focused on two periods: 2002-2010 (the last business cycle) and 1992-2001 (the prior complete business cycle).

Q. Please describe your CE analysis.

A. Schedules 10 and 11 contain summaries of experienced returns on equity for several groups of companies, while Schedule 12 presents a risk comparison of utilities versus unregulated firms.

Schedule 10 shows the earned returns on average common equity and market-to-book ratios for the two groups of proxy utilities. These can be summarized as follows:

	Proxy Group	Hevert Group
Historic ROE		
Mean	11.0-11.2%	12.3-12.5%
Median	11.4-11.6%	12.2-12.3%
Historic M/B		
Mean	170-172%	185-188%
Median	169-174%	185%
Prospective ROE		
Mean	10.9-11.3%	11.6-11.8%
Median	10.0-10.5%	10.0-11.0%

These results indicate that historic returns of 11.0 percent to 12.5 percent have been adequate to provide market-to-book ratios of 169 percent to 188 percent for the groups of proxy utilities. Furthermore, projected returns on equity for 2011, 2012 and 2014-2016 are within a range of 10.0 percent to 11.8 percent for the utility groups. These relate to 2010 market-to-book ratios of 160 percent or greater.

Q. Have you also reviewed earnings of unregulated firms?

A. Yes. As an alternative, I also examined a group of largely unregulated firms. I have examined the Standard & Poor's 500 Composite group, because this is a well recognized group of firms that is widely utilized in the investment community and is indicative of the competitive sector of the economy. Schedule 11 presents the earned returns on equity and market-to-book ratios for the S&P 500 group over the past eighteen years. As this Schedule indicates, over the two periods this group's average earned returns ranged from 12.1 percent to 14.7 percent with market-to-book ratios ranging between 265 percent and 341 percent.

Q. How can the above information be used to estimate the cost of equity for Southwest Gas?

A. The recent earnings of the proxy utility and S&P 500 groups can be utilized as an indication of the level of return realized and expected in the regulated and competitive sectors of the economy. In order to apply these returns to the cost of equity for proxy utilities, however, it is necessary to compare the risk levels of the utility industry with those of the competitive sector. I have done this in Schedule 12, which compares several risk indicators for the S&P 500 group and the utility groups. The information in this schedule indicates that the S&P 500 group is more risky than the utility proxy groups.

Q. What return on equity is indicated by the CE analysis?

A. Based on the recent earnings and market-to-book ratios, I believe the CE analysis indicates that the cost of equity for the proxy utilities is no more than 9.5 percent to 10.5 percent (10.0 percent mid-point). Recent returns of 11.0 percent to 12.5 percent have resulted in market-to-book ratios of 170 and greater. Prospective returns of 10.0 percent to 11.8 percent result in anticipated market-to-book ratios of 160 percent or over. As a result, it is apparent that returns below this level would result in market-to-book ratios of well above 100 percent. Accordingly, an earned return of 9.5 percent to 10.5 percent should result in a market-to-book ratio of over 100 percent. As I indicated earlier, the fact that market-to-book ratios substantially exceed 100 percent indicates that historic and prospective returns of 11 percent to 12 percent reflect earnings levels that exceed the cost of equity for those regulated companies.

In applying the CE analysis, it also is important to recognize recent trends. My recommended range of 9.5 percent to 10.5 percent is further supported by the actual newly authorized returns on common equity from 2002 through 2010, which are as follows for U.S. natural gas utilities as authorized by state regulatory agencies:

Year	ROE
2002	11.16%
2003	11.05%
2004	10.67%
2005	10.50%
2006	10.44%
2007	10.21%
2008	10.36%
2009	10.15%
2010	10.06%

Source: Exhibit No. ___ (RBH-6) of Company Filing.

Please also note that my CE analysis is not based on a mathematic formula approach, as are the DCF and CAPM methodologies. Rather, it is based on recent trends and current conditions in equity markets. Further, it is based on the direct relationship between returns on common stock and market-to-book ratios of common stock. In utility rate setting, a fair rate of return is generally based on the utility's assets (i.e., rate base) and the book value of the utility's capital structure. As stated earlier, maintenance of a financially stable utility's market-to-book ratio at 100%, or a bit higher, is fully adequate to maintain the utility's financial stability. On the other hand, a market price of a utility's common stock that is 150 percent or more above the stock's book value is indicative of earnings that exceed the utility's reasonable cost of capital. Thus, actual or projected earnings do not directly translate into a utility's reasonable cost of equity. Rather, they must be viewed in relation to the market-to-book ratios of the utility's common stock.

My 9.5 percent to 10.5 percent CE recommendation reflects the fact that historic equity returns of 11.0 percent to 12.5 percent have resulted in market-to-book ratios of 170 percent to 190 percent, which demonstrates that the equity returns exceed the cost of capital. Likewise, projected returns of about 10.0 percent to 11.8 percent relate to 2010 market-to-book ratios of 160 percent and over. My 9.5 percent to 10.5 percent CE recommendation is not designed to result in market-to-book ratios as low as 1.0 for Southwest Gas. Rather, it is based on current market conditions and the proposition that ratepayers should not be required to pay rates based on earnings levels that result in excessive market-to-book ratios.

XI. RETURN ON EQUITY RECOMMENDATION

Q. Please summarize the results of your three cost of equity analyses.

A. My three methodologies produce the following:

Discounted Cash Flow	9.0-9.6%
Capital Asset Pricing Model	7-9-8.0%
Comparable Earnings	9.5-10.5%

My overall conclusion from these results is a reasonable range of 9.0 percent to 10.5 percent, which focuses on the respective model findings for the DCF and CE analyses. The mid-point of this range is 9.75 percent.

Q. What cost of equity do you recommend for Southwest Gas?

A. I recommend a cost of equity of 9.75 percent.

Q. It appears that your CAPM results are somewhat lower than your DCF and CE results. Does this indicate that the CAPM results should not be considered at this time?

A. No, this is not the case. Although my recommended range is above the CAPM results, I have not disregarded the CAPM results. It is apparent that the CAPM results are lower than the DCF results, as well as being lower than CAPM results in recent years. The two reasons for this are the current relatively low yields on U.S. Treasury bonds (i.e., risk-free rate) and a lower risk premium that reflects the decline in stock prices of the past few years. Each of these factors is a result of the recent financial crisis and concurrent recession. As a result, I do not give significant weight to the CAPM results in deriving my return on equity recommendation. On the other hand, the same factors that are creating downward pressure on the CAPM results are also indicative of a decline in capital costs in the economy at this time.

Q. Your 9.75 percent return on equity recommendation is less than the 10.0 percent authorized by the Commission in the last rate proceeding of Southwest Gas. Is a reduction in the Company's authorized return on equity appropriate at this time?

A. Yes, it is. The 10.0 percent cost of equity found appropriate by the Commission in Docket No. G-01551-07-0504 was applicable to a capital structure containing 43.44 percent common equity, which is well below the 52.3 percent common equity contained in the current cost of capital request of the Company. The currently higher equity ratio is reflective of a reduced level of financial risk for the Company, which is also indicative of a reduction in the cost of common equity. I have also noted that authorized common equity cost rates are recently lower than was the case three years ago in Southwest Gas' last rate proceeding. This is also reflective of a decline in the cost of common equity. In this regard, I note that even the Company acknowledges a lower cost of common equity, as its currently-requested 11.0 percent cost of equity is less than the 11.25 percent cost of equity requested in the prior proceeding.

XII. TOTAL COST OF CAPITAL

Q. What is the total cost of capital for Southwest Gas?

A. Schedule 1 reflects the total cost of capital for the Company using the actual capital structure and cost of long-term debt, and my common equity cost recommendations. The resulting total cost of capital is a range of 8.69 percent to 9.47 percent (9.08 percent with 9.75 percent cost of equity). I recommend that this 9.08 percent total cost of capital be established for Southwest Gas.

Q. Does your cost of capital recommendation provide the Company with a sufficient level of earnings to maintain its financial integrity?

A. Yes, it does. Schedule 13 shows the pre-tax coverage that would result if Southwest Gas earned my cost of capital recommendation. As the results indicate, my recommended range would produce a coverage level within the benchmark range for a Single A rated utility. In addition, the debt ratio (which reflects the Company's proposed capital structure) is within the benchmark for a Single A rated utility.

XIII. COMMENTS ON COMPANY TESTIMONY

Q. Have you reviewed the cost of capital testimony of Southwest Gas witness Robert B. Hevert?

A. Yes, I have.

Q. Please summarize your understanding of Mr. Hevert's cost of equity recommendations.

A. Mr. Hevert proposes an equity return for Southwest Gas of 11.0 percent. This recommendation is based upon the results of several sets of DCF, CAPM, and risk premium models, as is shown in Table 7 on page 46 of his direct testimony, and as summarized below:

	Mean Low	**Mean**	**Mean High**
Constant Growth DCF			
30-Day Average	7.43%	8.39%	9.55%
90-Day Average	7.54%	8.50%	9.65%
180-Day Average	7.59%	8.55%	9.71%
Multi-Stage DCF			
30-Day Average	10.08%	10.28%	10.48%
90-Day Average	10.36%	10.48%	10.60%
180-Day Average	10.49%	10.58%	10.66%

Supporting Methodologies

	Near Term 30-Year (3.75%)	**Long-Term Projected 30-Year Treasury (4.22%)**
CAPM - Current Calculated Beta		
Sharpe Ratio Derived Market Risk Premium	12.40%	12.87%
Market DCF Derived Market Risk Premium	11.94%	12.42%
CAPM - Average Historical Beta		
Sharpe Ratio Derived Market Risk Premium	10.41%	10.88%
Market DCF Derived Market Risk Premium	10.06%	10.53%

Treasury Yield Plus Risk Premium

	Mean Low	**Mean**	**Mean High**
Risk Premium	10.23%	10.55%	11.01%

Mr. Hevert maintains that his 11.0 percent recommended return on equity is "based on the various quantitative and qualitative analyses" in his testimony. *See* Hevert Direct at 45, lines 8-9. However, it is apparent that Mr. Hevert's return on equity recommendation is not supported by his analyses.

Q. Do you have any general observations about Mr. Hevert's analyses and conclusions?

A. Yes, I do. It is apparent from Mr. Hevert's Table 7 (as reproduced above) that his 11.0 percent return on equity can only be rationalized by use of the "Current Calculated Beta" CAPM results and the "Mean High" risk premium. Mr. Hevert's "Mean" Constant Growth DCF results indicate 8.39 percent to 8.55 percent results, while even his "Mean High" constant Growth DCF results are 9.71 percent or less. In addition, all of Mr. Hevert's Multi-Stage DCF results indicate a cost of equity of about 10.0 percent to 10.7 percent. I will show below that even these results are over-stated.

I also note that the historic beta CAPM and Risk Premium results using "near-term" U.S. Treasury Bond yields in Mr. Hevert's Table 7 are within a range of about 10.0 percent to 10.5 percent. I will also show that even these results are over-stated.

Q. What are your disagreements with Mr. Hevert's constant growth DCF analyses?

A. Mr. Hevert's Constant Growth DCF analyses are based on 30-day, 90-day and 180-day average stock prices for the periods ending October 8, 2010, annualized dividends per share as of October 8, 2010 and the average of Value Line, First Call, and Zack's EPS projections and projected Retention Growth rates. His DCF analyses are applied to his group of nine natural gas distribution utilities.

Mr. Hevert's Constant Growth DCF analyses are shown on his Exhibit RBH-1. It is apparent from this that his "Low DCF ROE" for each proxy company reflects the dividend yield and the lowest of the four growth rates he considers. His "Mean DCF ROE" considers the average of all four growth rates; and the "High DCF ROE" only considers the highest growth rate for each company. Stated differently, the "Mean High DCF" result considers only the highest of the four growth rates for each company and ignores the other three growth rates. Thus, the "Mean High DCF" result for one proxy company may reflect only the Zacks EPS Growth, while the "Mean High DCF" result for another proxy company may reflect only the BR + SV (Retention Growth) growth result. This implicitly assumes that investors *only* consider the most optimistic growth rate for each individual company in making investment decisions.

It is further apparent that Mr. Hevert's methodology exclusively focuses on three of the four growth rates for at least one proxy company. For example, his "High DCF ROE" for his nine proxy companies relies exclusively on the following growth rates:

AGL Resources	First Call EPS
Atmos Energy	Value Line EPS
Laclede Group	BR + SV
New Jersey Resources	BR + SV
Nicor	BR + SV
Northwest Natural Gas	BR + SV
Piedmont Natural Gas	Zacks EPS
South Jersey Industries	BR + SV
Southwest Gas	BR + SV

Q. Is it appropriate to focus on the highest growth rate, on a company-to-company basis, to determine the cost of equity for a natural gas distribution company such as Southwest Gas?

A. No. It is neither realistic nor proper to focus on a single growth rate in a DCF context, especially when one "cherry picks" the highest growth rate for each company from among the different growth rate indicators that reflect the highest growth rate for each company.

Q. Are there any other problems with Mr. Hevert's constant growth DCF analyses?

A. Yes. Even though Mr. Hevert purports to examine four alternative growth rates in his Constant Growth DCF analyses, in reality each of the four focuses on a single statistic: analysts' forecasts of EPS. Three of the four growth rates directly use EPS forecasts including those by Zacks, Value Line and First Call. The other growth rate, BR + SV, uses EPS forecasts as a component. As a result, all of Mr. Hevert's Constant Growth rates in reality focus on EPS forecasts of security analysts.

Q. Why is it improper to rely on EPS forecasts in a DCF analysis?

A. There are several reasons why it is not proper to rely on analysts' forecasts in a DCF context. First, it is not realistic to believe that investors rely exclusively on a single factor, such as analysts' forecasts, in making their investment decisions. Investors have an abundance of available information to assist them in evaluating stocks and EPS forecasts are only one of many such statistics.

Second, Value Line – one of Mr. Hevert's sources of EPS projections – publishes a large number of individual company data and ratios. Presumably these are published for the consideration of subscribers/investors. It is also apparent that Value Line publishes both *historic* and forecast data. Yet, Mr. Hevert considers only *one* factor and only the *forecast* version of this factor.

Third, the vast majority of information available to investors, by both individual companies in the form of annual reports and offering circulars, and by investment publications such as Value Line, is historic data. It is neither realistic nor logical to maintain that investors only consider projected (estimated) data to the exclusion of historic (actual) data.

Fourth, there have been a number of academic studies that indicate that analysts' forecasts have been overly-optimistic in the past. See, for example a 1998 article in *Financial Analysts Journal*, Vol. 54, No. 6, Nov./Dec. 1998, 35-42, titled "Why So Much Error In Analysts' Earnings Forecasts?" by Vijay Kumer Chopra. In this article, the author concluded "Analysts' forecasts of EPS and growth in EPS tend to be overly optimistic." He reasoned that analysts' forecasts of EPS over the past 13 years have been more than twice the actual growth rate. Investors are aware of the propensity of analysts to over-estimate EPS forecasts. In addition, the presumption that investors rely *only* on a single projection, as was made by Mr. Hevert, implies that investors are unsophisticated and unable to make their own decisions. This also is not realistic.

Fifth, the experience over the past three years should be a clear signal to investors that analysts cannot accurately predict EPS levels. Few, if any, analysts predicted the decline in security prices in 2008 and 2009. Thus, relying only on forecasted EPS levels, and not also looking at historic EPS levels, will not produce accurate results.

In summary, investors are now very much aware of recent scandals involving security analysts' conflicts of interest, including the Enron and WorldCom debacles, that have resulted in settlements, fines, and public admonishments, as well as other negative connotations related to the reliability of analysts' forecasts. These problems clearly call into question the reliance of analysts' forecasts as the *only* source of growth in a DCF context. As a result, the landscape has changed in recent years and investors have ample reasons to doubt the reliability of such forecasts at the present time. In any event, it is problematic to rely exclusively on such forecasts in determining the cost of equity for Southwest Gas.

Q. What is your response to Mr. Hevert's "multi-stage" DCF analyses?

A. Mr. Hevert's Multi-Stage DCF results are shown on his Exhibit No. RBH-3. For each of the nine proxy companies he uses, the third growth stage (*i.e.,* Terminal Growth) is an estimate of the long-term growth rate of Gross Domestic Product ("GDP"). Mr. Hevert's estimate of long-term GDP growth (5.83 percent) is determined by combining the "real" GDP growth rate from 1929 through 2009 with projections of inflation by Blue Chip Economic Indicators and the Energy Information Administration ("EIA").

There are three problems associated with Mr. Hevert's long-term GDP component in his DCF analysis. First, Mr. Hevert refuses to even consider historic growth in his Constant Growth DCF analyses and as the short-term growth rates in his Multi-Stage DCF analyses, yet he focuses *exclusively* on historic values of real GDP growth in his Multi-Stage DCF analyses. This is an inconsistency in his testimony. It also is indicative of his practice of only focusing on the highest growth rates in his cost of capital analyses.

Second, the EIA publication cited by Mr. Hevert also contains an estimate of long-term real GDP growth. *See*, Hevert Direct at 24, lines 1-3. Mr. Hevert could have consistently taken the long-term GDP estimate from EIA and combined this with EIA's long-term estimate of CPI. Had he done so, the real GDP growth rate would have been 2.7 percent, rather than the 3.28 percent Mr. Hevert employs. Schedule 14 shows this EIA GDP growth rate.

Third, Mr. Hevert improperly combines the CPI with real GDP growth. Since he is allegedly focusing on the long-term growth rate of the economy, he should have used the "GDP Chain-Type Price Index," which is specifically developed for use with GDP. I note that the EIA projections of this index (1.8 percent), also shown on Schedule 14, are lower than those for CPI (2.4 percent).

Q. What would be the impact of Mr. Hevert using a long-term growth rate as the third stage of his multi-stage DCF analyses?

A. The impact would be to produce lower results than those contained in his Table 7.

Q. You previously noted that Mr. Hevert's CAPM results are his highest. Do you have any response to his CAPM analyses?

A. Mr. Hevert recognizes there are published sources of the beta component of the CAPM equation. *See* Hevert Direct at 28, lines 10-12. However, unlike investors who subscribe to the sources of the published betas *i.e.,* Value Line and Bloomberg, Mr. Hevert substitutes his own "calculated" betas. His "calculated" betas only consider twelve months of stock price data (page 28, lines 23-26) and are higher (average of 0.876) than those published by Value Line and Bloomberg (0.67, as shown on Mr. Hevert's Exhibit RBH-4, Page 8).

Q. Do you agree with Mr. Hevert's risk premium component of the CAPM?

A. No. Mr. Hevert utilizes two risk premium values: 9.42 percent and 9.94 percent. *See,* Hevert Direct at 27 and 28. Both of these greatly exceed the long-term experience (*e.g.,* 1929 to present) of investment return differential between common stocks and government bonds, as described earlier in my testimony.

Q. Do you have any responses to Mr. Hevert's risk premium analyses?

A. Yes. Mr. Hevert's risk premium approach compares the allowed ROEs for natural gas distribution utilities and 30-Year U.S. Government Bond yields over the period 1992 to the third quarter of 2010. He then performs a regression analyses to develop an expected relationship between 30-Year U.S. Government Bond yields and the cost of equity for natural gas distribution companies. He apples this regression result (page 33) to the two projections of 30-Year US Treasury Bonds cited in his CAPM analyses (*i.e.,* 3.75 percent and 4.22 percent) and correspondingly arrives at his 10.23 percent to 11.01 percent conclusion.

It is apparent from Mr. Hevert's Exhibit No. RBH-6 that the actual authorized returns on equity for gas distribution utilities have averages well below the 10.23 percent to 11.01 percent he proposes. In contrast, his exhibit shows recent (*i.e.,* 2007 to present) average quarterly authorized returns on equity between 9.88 percent and 10.57 percent. As shown on Mr. Hevert's own exhibit, over the past six quarters, the average authorized returns on equity have been:

2009 Q2	10.19%
2009 Q3	9.88%
2009 Q4	10.27%
2010 Q1	10.24%
2010 Q2	9.99%
2010 Q3	9.93%
Average	10.08%

Q. Mr. Hevert also "considers" flotation costs in his 11.0 percent conclusion. Do you agree with the inclusion of flotation costs in determining Southwest Gas return on equity?

A. No. It is not proper to include a flotation cost adjustment in determining the cost of equity for Southwest Gas. Even though Mr. Hevert maintains that he does not make an "explicit adjustment" for flotation costs, he does "consider" these impacts in reaching his conclusion. *See* Hevert Direct at 41, lines 8-10. As a result, he is still making an "implicit adjustment" for flotation costs.

XIV. FAIR VALUE RATE BASE COST OF CAPITAL

Q. What is your understanding of Southwest Gas' position on the issue of fair value rate base and related cost of capital implications?

A. It is my understanding that Southwest Gas is requesting that the fair value of its rate base be used in developing its rates. The Company does not appear to be requesting that its weighted cost of capital be applied to the level of its fair value rate base.

Q. What is your understanding of the Commission's procedure for utilizing the fair value of rate base in setting utility rates?

A. My "non-legal understanding" is that the Commission must consider the fair value of a utility's assets in setting rates. However, I do not agree that this implies that the Company's cost of capital must be applied to the fair value of the rate base.

Q. What is your understanding of the use of fair value rate base in Arizona?

A. My "non-legal understanding" is based in part on the 2006 Arizona Court of Appeals in the Chaparral City case that indicates that the Court agreed with the Commission that "the cost of capital analysis 'is geared to concepts of original cost measures of rate base, not fair value measures of rate base . . . ." The decision goes on to make the following statement: "If the Commission determines that the cost of capital analysis is not the appropriate methodology to determine the rate of return to be applied to the FVRB, the Commission has the discretion to determine the appropriate methodology." It is correspondingly the purpose of this section of my testimony to recommend an "appropriate methodology" for use in conjunction with a FVRB.

Q. Do you have any observations based upon your own experience in cost of capital determination, as to whether a cost of capital developed for application to an original cost rate base is consistent with a fair value rate base?

A. Yes, I do. It is my personal experience, based upon nearly 40 years of providing cost of capital testimony, that the concept of cost of capital is designed to apply to an original cost rate base. This is the case since the cost of capital is derived from the liabilities/owners' equity side of a utility's balance sheet using the book values of the capital structure components. The cost of capital, once determined, is then applied to (i.e., multiplied by) the rate base, which is derived from the asset side of the balance sheet (i.e., OCRB). From a financial perspective, the rationale for this relationship is that the rate base is financed by the capitalization. Under this relationship, a provision is provided for investors (both lenders and owners) to receive a return on their invested capital. Such a relationship is meaningful as long as the cost of capital is applied to the original cost (i.e., book value) rate base, because there is a matching of rate base and capitalization.

When the concept of fair value rate base is incorporated, however, this link between rate base and capital structure is broken. The amount of fair value rate base that exceeds original cost rate base is not financed with investor-supplied funds and, indeed, is not financed at all. As a result, a customary cost of capital analysis cannot be automatically applied to the fair value rate base since there is no financial link between the two concepts. In my "non-legal" opinion, both the Commission and Appeals Court have also recognized this lack of compatibility between a customary weighted cost of capital ("WCOC") analysis and FVRB.

Q. Why is it important that there be a link between the concepts of rate base and cost of capital?

A. This link is important since financial theory indicates that investors should be provided an opportunity to earn a return on the capital they provided to the utility. Since the capital finances the rate base (in an original cost world), the link between cost of capital and rate base satisfies this financial objective.

Q. Based on your experience as a cost of capital witness over the past 40 years, do you have a *suggestion* as to how to account for the use of a FVRB in setting rates for Southwest Gas?

A. Yes, I do. Since the increment between fair value rate base and original cost rate base is not financed with investor-supplied funds, it is logical and appropriate, from a financial standpoint, to assume that this increment has no financing cost. As a result, the cost of capital, through the capital structure, can be modified to account for a level of cost-free capital in an equal dollar amount to the increment of FVRB over the OCRB. Such a procedure would still provide for a return being earned on all investor-supplied funds and would thus be consistent with financial standards.

Q. Have you made such a proposal in this proceeding?

A. Yes, I have. As is shown below, I have developed a capital structure and FVROR that applies to Southwest Gas' FVRB.

Item	Percent[4]	Cost	Fair Value Return
Short-term Debt[5]	0.00%	--	--
Long-term Debt	35.13%	8.34%	2.93%
Common Equity	38.52%	9.75%	3.76%
FVRB Increment[6]	26.35%	0.00%	0.00%
Total FVRB Capital	100.00%		6.69%

Applying this 6.69 percent to the FVRB provides for a return on *all investor*-supplied capital and is therefore an appropriate rate to apply to the FVRB from a financial and

4 As shown in Testimony of Utilities Division Staff witness Ralph Smith.

5 As is the case for my cost of capital calculations, no short-term debt is included since the Company had none at the end of the test period.

6 FVRB minus OCRB.

economic standpoint. As such, it provides for an appropriate fair value rate of return to be applied to a FVRB. Staff also refers to this as Method 1.

Q. Have you developed an alternative method with which to apply a FVROR to a FVRB?

A. Yes, I have. Should the Commission determine that there should be a specific return (greater than zero) applied to the FVRB Increment, I have provided such a procedure.

Q. Why is it necessary to add a return on only the portion of FVRB that exceeds the OCRB?

A. The WCOC authorized by the Commission has already provided for a full cost of equity return and cost of debt on the portions of equity and debt capital that are supporting the OCRB portion of the FVRB. As a result, there is no need to provide any additional return on the portions of FVRB supported by common equity and debt.

Stated differently, both the cost of debt and the return on common equity (i.e., capital stock, paid-in capital, and retained earnings - the investment of common shareholders) are already provided for in a traditional WCOC. Only the portion of the FVRB that exceeds OCRB ("Fair Value Increment") needs to have a specific return identified in order to reflect a return component on that Fair Value Increment.

Q. What is the proper cost rate to apply to the Fair Value Increment?

A. As I indicated previously, from a financial perspective, it should not be necessary to provide for <u>any</u> return on the Fair Value Increment since this is not investor-supplied capital. However, the Commission may choose to evaluate this issue from both a financial and a public policy perspective. I am aware that Southwest Gas may claim that the concept of fair value carries with it the notion that investors should receive some benefit when fair value is greater than original cost and should suffer some detriment when fair value is less than original cost. It is possible that the Commission may determine that Arizona's fair value provision, which is somewhat unique, is not inconsistent with these concepts. Nonetheless, the idea that the Company should receive some benefit from the Fair Value Increment does not mean that one should automatically apply to the FVRB a WCOC developed by reference to original cost rate base. If it is determined that it is desirable to provide an additional (non-zero) return on the Fair Value Increment, the proper return should be no larger than the real (i.e., after inflation is removed) risk-free rate of return.

Q. What is the risk-free return?

A. The risk-free return is, in financial terms, the return on an investment that carries little or no risk. Risk-free investments are universally defined as U.S. Treasury Securities, with short-term maturities usually being used as the risk-free rate. Over the past several months, various maturities of U.S. Treasury securities have yielded from about 0.2 percent (short-term) to 4.5 percent (long-term) in nominal terms. I also note that 2011 forecasts of long-term U.S. Treasury securities are about 4.0 percent to 5.0 percent. As a result, I use 4.5 percent as the nominal risk-free rate.

Q. What is the "real" risk-free rate?

A. The concept of real rates involves the removal of the rate of inflation from the nominal risk-free rate. In 2010, the rate of inflation, as measured by the Consumer Price Index ("CPI"), was 1.5 percent. Forecasts of the CPI for 2011-2012 are about 2 percent or less. As a result, I propose to use a 2 percent inflation rate for computing the real risk-free rate, which is computed as follows:

Nominal Risk-Free Rate	4.5%
Less: Inflation Rate	2.0%
Equals: Real Risk-Free Rate	2.5%

Q. Please explain why Southwest Gas' FVROR should consider the real risk-free rate, as opposed to the nominal risk-free rate.

A. The investors of Southwest Gas are already receiving an inflation factor due to the inclusion of inflation in the FVRB Increment. Specifically, the Fair Value Increment incorporates inflation by considering the current value of assets, which reflect, in part, past inflation. It would be double-counting to also include the inflation components in the return to be applied to the FVRB Increment.

Q. What return on the Fair Value Increment do you recommend in your alternative FVROR proposal?

A. My alternative FVROR proposal ("Method 2") incorporates a return on the Fair Value Increment with a maximum value of 2.5 percent, as developed above. However, I wish to emphasize that this 2.5 percent value is the maximum value that could be applied to the FVRB Increment. In reality, any value between zero percent and 2.5 percent could be used as the cost rate on the FVRB Increment. As I stated above, this Fair Value Increment return is in addition to the return that the Company's investors already earn on their investment in the Company. In this sense, an above-zero cost rate for the fair value increment represents a bonus to the Company that would have to find its justification in policy considerations instead of in pure economic or financial principles; for that reason, the selection of an appropriate cost rate within this range should fall to the Commission's discretion. I would propose the mid-point of this range, or 1.25 percent.

Q. What is the resulting impact of your alternative proposal in this proceeding?

A. I am proposing the following modified FVROR for Southwest Gas:

Capital Item	Percent	Cost	Return
Short-term Debt	0.00%	--	--
Long-term Debt	35.13%	8.34%	2.93%
Common Equity	38.52%	9.75%	3.76%
FVRB Increment	26.35%	1.25%	0.33%
Total	100.00%		7.02%

As shown in the above table, this alternative proposal provides for a non-zero return on the Fair Value Increment of Southwest Gas, and provides for an overall fair value rate of return of 7.02 percent on the FVRB.

Q. Of the two alternative proposals for determining the fair value rate of return that should be applied to the FVRB, which one do you believe is more appropriate and why?

A. From a financial perspective, I believe the first proposal (i.e., zero-cost for FVRB Increment) is most appropriate. This proposal is consistent with financial principles and would fully compensate the Company's investors for their investment. In addition, this proposal utilizes the FVRB of the Company. On the other hand, if the Commission were to determine that a non-zero return on the Fair Value Increment is desirable, the alternative (i.e., a 1.25% cost-rate for the FVRB increment) is not inappropriate. It is my understanding that this second alternative was utilized by the Commission in Southwest Gas' last rate proceeding.

Q. Do these proposals provide for a return on the FVRB of Southwest Gas?

A. Yes, they do.

Q. Will Staff continue to evaluate appropriate methods for determining the fair value rate of return on fair value rate base?

A. It is my understanding that the Commission Staff will continue to consider these issues in the context of future rate cases. Individual rate cases present different issues and varying sets of circumstances. For example, if one were to assign a non-zero cost rate to the fair value increment, it may be appropriate to determine the cost of equity to reflect a reduction in risk. I have not proposed such an adjustment in this case, but these issues may appear as Staff continues to consider appropriate methods for determining and evaluating the concept of fair value rate of return on fair value rate base.

Q. Does this conclude your Direct Testimony?

A. Yes.

BACKGROUND AND EXPERIENCE PROFILE
DAVID C. PARCELL, MBA, CRRA
PRESIDENT/SENIOR ECONOMIST

EDUCATION

1985	M.B.A., Virginia Commonwealth University
1970	M.A., Economics, Virginia Polytechnic Institute and State University, (Virginia Tech)
1969	B.A., Economics, Virginia Polytechnic Institute and State University, (Virginia Tech)

POSITIONS

2007-Present	President, Technical Associates, Inc.
1995-2007	Executive Vice President and Senior Economist, Technical Associates, Inc.
1993-1995	Vice President and Senior Economist, C. W. Amos of Virginia
1972-1993	Vice President and Senior Economist, Technical Associates, Inc.
1969-1972	Research Economist, Technical Associates, Inc.
1968-1969	Research Associate, Department of Economics, Virginia Polytechnic Institute and State University

ACADEMIC HONORS

Omicron Delta Epsilon - Honor Society in Economics
Beta Gamma Sigma - National Scholastic Honor Society of Business Administration
Alpha Iota Delta - National Decision Sciences Honorary Society
Phi Kappa Phi - Scholastic Honor Society

PROFESSIONAL DESIGNATION

Certified Rate of Return Analyst - Founding Member

RELEVANT EXPERIENCE

Financial Economics -- Advised and assisted many Virginia banks and savings and loan associations on organizational and regulatory matters. Testified approximately 25 times before the Virginia State Corporation Commission and the Regional Administrator of

National Banks on matters related to branching and organization for banks, savings and loan associations, and consumer finance companies. Advised financial institutions on interest rate structure and loan maturity. Testified before Virginia State Corporation Commission on maximum rates for consumer finance companies.

Testified before several committees and subcommittees of Virginia General Assembly on numerous banking matters.

Clients have included First National Bank of Rocky Mount, Patrick Henry National Bank, Peoples Bank of Danville, Blue Ridge Bank, Bank of Essex, and Signet Bank.

Published articles in law reviews and other periodicals on structure and regulation of banking/financial services industry.

Utility Economics -- Performed numerous financial studies of regulated public utilities. Testified in over 300 cases before some thirty state and federal regulatory agencies.

Prepared numerous rate of return studies incorporating cost of equity determination based on DCF, CAPM, comparable earnings and other models. Developed procedures for identifying differential risk characteristics by nuclear construction and other factors.

Conducted studies with respect to cost of service and indexing for determining utility rates, the development of annual review procedures for regulatory control of utilities, fuel and power plant cost recovery adjustment clauses, power supply agreements among affiliates, utility franchise fees, and use of short-term debt in capital structure.

Presented expert testimony before federal regulatory agencies Federal Energy Regulatory Commission, Federal Power Commission, and National Energy Board (Canada), state regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, District of Columbia, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Maine, Maryland, Missouri, Nebraska, Nevada, New Hampshire, New Jersey, New Mexico, Ohio, Oklahoma, Ontario (Canada), Pennsylvania, South Carolina, Texas, Utah, Vermont, Virginia, West Virginia, Washington, Wisconsin, and Yukon Territory (Canada).

Published articles in law reviews and other periodicals on the theory and purpose of regulation and other regulatory subjects.

Clients served include state regulatory agencies in Alaska, Arizona, Delaware, Missouri, North Carolina, Ontario (Canada), and Virginia; consumer advocates and attorneys general in Alabama, Arizona, District of Columbia, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Maryland, Nevada, New Mexico, Ohio, Oklahoma, Pennsylvania, South Carolina, Texas, Utah, Vermont, Virginia, and West Virginia; federal agencies including Defense Communications Agency, the Department of Energy, Department of the Navy, and General Services Administration; and various organizations such as Bath Iron Works, Illinois Citizens' Utility Board, Illinois Governor's Office of Consumer Services, Illinois Small Business Utility Advocate, Wisconsin's Environmental Decade, Wisconsin's Citizens Utility Board, and Old Dominion Electric Cooperative.

Insurance Economics -- Conducted analyses of the relationship between the investment income earned by insurance companies on their portfolios and the premiums charged for insurance. Analyzed impact of diversification on financial strength of Blue Cross/Blue Shield Plans in Virginia.

Conducted studies of profitability and cost of capital for property/casualty insurance industry. Evaluated risk of and required return on surplus for various lines of insurance business.

Presented expert testimony before Virginia State Corporation Commission concerning cost of capital and expected gains from investment portfolio. Testified before insurance bureaus of Maine, New Jersey, North Carolina, Rhode Island, South Carolina and Vermont concerning cost of equity for insurance companies.

Prepared cost of capital and investment income return analyses for numerous insurance companies concerning several lines of insurance business. Analyses used by Virginia Bureau of Insurance for purposes of setting rates.

Special Studies -- Conducted analyses which evaluated the financial and economic implications of legislative and administrative changes. Subject matter of analyses include returnable bottles, retail beer sales, wine sales regulations, taxi-cab taxation, and bank regulation. Testified before several Virginia General Assembly subcommittees.

Testified before Virginia ABC Commission concerning economic impact of mixed beverage license.

Clients include Virginia Beer Wholesalers, Wine Institute, Virginia Retail Merchants Association, and Virginia Taxicab Association.

Franchise, Merger & Anti-Trust Economics -- Conducted studies on competitive impact on market structures due to joint ventures, mergers, franchising and other business restructuring. Analyzed the costs and benefits to parties involved in mergers. Testified in federal courts and before banking and other regulatory bodies concerning the structure and performance of markets, as well as on the impact of restrictive practices.

Clients served include Dominion Bankshares, asphalt contractors, and law firms.

Transportation Economics -- Conducted cost of capital studies to assess profitability of oil pipelines, trucks, taxicabs and railroads. Analyses have been presented before the Federal Energy Regulatory Commission and Alaska Pipeline Commission in rate proceedings. Served as a consultant to the Rail Services Planning Office on the reorganization of rail services in the U.S.

Economic Loss Analyses -- Testified in federal courts, state courts, and other adjudicative forums regarding the economic loss sustained through personal and business injury whether due to bodily harm, discrimination, non-performance, or anticompetitive practices. Testified on economic loss to a commercial bank resulting from publication of adverse information concerning solvency. Testimony has been presented on behalf of private individuals and business firms.

MEMBERSHIPS

American Economic Association
Virginia Association of Economists
Richmond Society of Financial Analysts
Financial Analysts Federation
Society of Utility and Regulatory Financial Analysts

Board of Directors	1992-2000
Secretary/Treasurer	1994-1998
President	1998-2000

RESEARCH ACTIVITY

Books and Major Research Reports

"Stock Price As An Indicator of Performance," Master of Arts Thesis, Virginia Tech, 1970

"Revision of the Property and Casualty Insurance Ratemaking Process Under Prior Approval in the Commonwealth of Virginia," prepared for the Bureau of Insurance of the Virginia State Corporation Commission, with Charles Schotta and Michael J. Ileo, 1971

"An analysis of the Virginia Consumer Finance Industry to Determine the Need for Restructuring the Rate and Size Ceilings on Small Loans in Virginia and the Process by which They are Governed," prepared for the Virginia Consumer Finance Association, with Michael J. Ileo, 1973

State Banks and the State Corporation Commission: A Historical Review, Technical Associates, Inc., 1974

"A Study of the Implications of the Sale of Wine by the Virginia Department of Alcoholic Beverage Control", prepared for the Virginia Wine Wholesalers Association, Virginia Retail Merchants Association, Virginia Food Dealers Association, Virginia Association of Chain Drugstores, Southland Corporation, and the Wine Institute, 1983.

"Performance and Diversification of the Blue Cross/Blue Shield Plans in Virginia: An Operational Review", prepared for the Bureau of Insurance of the Virginia State Corporation Commission, with Michael J. Ileo and Alexander F. Skirpan, 1988.

The Cost of Capital - A Practitioners' Guide, Society of Utility and Regulatory Financial Analysts, 1997 (previous editions in 1991, 1992, 1993, 1994, and 1995).

Papers Presented and Articles Published

"The Differential Effect of Bank Structure on the Transmission of Open Market Operations," Western Economic Association Meeting, with Charles Schotta, 1971

"The Economic Objectives of Regulation: The Trend in Virginia," (with Michael J. Ileo), William and Mary Law Review, Vol. 14, No. 2, 1973

"Evolution of the Virginia Banking Structure, 1962-1974: The Effects of the Buck-Holland Bill", (with Michael J. Ileo), William and Mary Law Review, Vol. 16, No. 3, 1975

"Banking Structure and Statewide Branching: The Potential for Virginia", William and Mary Law Review, Vol. 18, No. 1, 1976

"Bank Expansion and Electronic Banking: Virginia Banking Structure Changes Past, Present, and Future," William and Mary Business Review," Vol. 1, No. 2, 1976

"Electronic Banking - Wave of the Future?" (with James R. Marchand), Journal of Management and Business Consulting, Vol. 1, No. 1, 1976

"The Pricing of Electricity" (with James R. Marchand), Journal of Management and Business Consulting, Vol. 1, No. 2, 1976

"The Public Interest - Bank and Savings and Loan Expansion in Virginia" (with Richard D. Rogers), University of Richmond Law Review, Vol. 11, No. 3, 1977

"When Is It In the 'Public Interest' to Authorize a New Bank?", University of Richmond Law Review, Vol. 13, No. 3, 1979

"Banking Deregulation and Its Implications on the Virginia Banking Structure," William and Mary Business Review, Vol. 5, No. 1, 1983

"The Impact of Reciprocal Interstate Banking Statutes on The Performance of Virginia Bank Stocks", with William B. Harrison, Virginia Social Science Journal, Vol. 23, 1988

"The Financial Performance of New Banks in Virginia", Virginia Social Science Journal, Vol. 24, 1989

"Identifying and Managing Community Bank Performance After Deregulation", with William B. Harrison, Journal of Managerial Issues, Vol. II, No. 2, Summer 1990

"The Flotation Cost Adjustment To Utility Cost of Common Equity - Theory, Measurement and Implementation," presented at Twenty-Fifth Financial Forum, National Society of Rate of Return Analysts, Philadelphia, Pennsylvania, April 28, 1993.

Biography of Myon Edison Bristow, Dictionary of Virginia Biography, Volume 2, 2001.

Exhibit___(DCP-1)
Schedule 1

SOUTHWEST GAS CORPORATION
TOTAL COST OF CAPITAL
AT JUNE 30, 2010

Item	Percent 1/		Cost			Weighted Cost	
Short-Term Debt	0.00% 2/						
Long-Term Debt	47.70%		8.34% 1/			3.98%	
Common Equity	52.30%	9.00%		10.50%	4.71%		5.49%
Total	100.00%				8.69%		9.47%
					Mid-Point	9.08%	

1/ As contained in Company filing, Schedule D-1, Page 1 of 2.

2/ Southwest Gas had no short-term debt outstanding at June 30, 2010, as indicated in the response to ACC-STF-2.5.

ECONOMIC INDICATORS

Year	Real GDP Growth*	Industrial Production Growth	Unemploy-ment Rate	Consumer Price Index	Producer Price Index
		1975 - 1982 Cycle			
1975	-1.1%	-8.9%	8.5%	7.0%	6.6%
1976	5.4%	10.8%	7.7%	4.8%	3.7%
1977	5.5%	5.9%	7.0%	6.8%	6.9%
1978	5.0%	5.7%	6.0%	9.0%	9.2%
1979	2.8%	4.4%	5.8%	13.3%	12.8%
1980	-0.2%	-1.9%	7.0%	12.4%	11.8%
1981	1.8%	1.9%	7.5%	8.9%	7.1%
1982	-2.1%	-4.4%	9.5%	3.8%	3.6%
		1983 - 1991 Cycle			
1983	4.0%	3.7%	9.5%	3.8%	0.6%
1984	6.8%	9.3%	7.5%	3.9%	1.7%
1985	3.7%	1.7%	7.2%	3.8%	1.8%
1986	3.1%	0.9%	7.0%	1.1%	-2.3%
1987	2.9%	4.9%	6.2%	4.4%	2.2%
1988	3.8%	4.5%	5.5%	4.4%	4.0%
1989	3.5%	1.8%	5.3%	4.6%	4.9%
1990	1.8%	-0.2%	5.6%	6.1%	5.7%
1991	-0.5%	-2.0%	6.8%	3.1%	-0.1%
		1992 - 2001 Cycle			
1992	3.0%	3.1%	7.5%	2.9%	1.6%
1993	2.7%	3.3%	6.9%	2.7%	0.2%
1994	4.0%	5.4%	6.1%	2.7%	1.7%
1995	2.5%	4.8%	5.6%	2.5%	2.3%
1996	3.7%	4.3%	5.4%	3.3%	2.8%
1997	4.5%	7.2%	4.9%	1.7%	-1.2%
1998	4.2%	5.9%	4.5%	1.6%	0.0%
1999	4.5%	4.3%	4.2%	2.7%	2.9%
2000	4.1%	4.0%	4.0%	3.4%	3.6%
2001	1.1%	-3.4%	4.7%	1.6%	-1.6%
		2002 - 2009			
2002	1.8%	0.2%	5.8%	2.4%	1.2%
2003	2.5%	1.3%	6.0%	1.9%	4.0%
2004	3.6%	2.3%	5.5%	3.3%	4.2%
2005	3.1%	3.2%	5.1%	3.4%	5.4%
2006	2.7%	2.2%	4.6%	2.5%	1.1%
2007	1.9%	2.7%	4.6%	4.1%	6.2%
2008	0.0%	-3.7%	5.8%	0.1%	-0.9%
2009	-2.6%	-11.2%	9.3%	2.7%	4.3%
		Current Cycle			
2010	2.9%	5.3%	9.6%	1.5%	4.0%

*GDP=Gross Domestic Product

Source: Council of Economic Advisors, Economic Indicators, various issues.

ECONOMIC INDICATORS

Year	Real GDP Growth	Industrial Production Growth	Unemploy-ment Rate	Consumer Price Index	Producer Price Index
2004					
1st Qtr.	3.0%	2.8%	5.6%	5.2%	5.2%
2nd Qtr.	3.5%	4.9%	5.6%	4.4%	4.4%
3rd Qtr.	3.6%	4.6%	5.4%	0.8%	0.8%
4th Qtr.	2.5%	4.3%	5.4%	3.6%	7.2%
2005					
1st Qtr.	3.0%	3.8%	5.3%	4.4%	5.6%
2nd Qtr.	2.6%	3.0%	5.1%	1.6%	-0.4%
3rd Qtr.	3.1%	2.7%	5.0%	8.8%	14.0%
4th Qtr.	2.1%	2.9%	4.9%	-2.0%	4.0%
2006					
1st Qtr.	5.4%	3.4%	4.7%	4.8%	-0.2%
2nd Qtr.	1.4%	4.5%	4.6%	4.8%	5.6%
3rd Qtr.	0.1%	5.2%	4.7%	0.4%	-4.4%
4th Qtr.	3.0%	3.5%	4.5%	0.0%	3.6%
2007					
1st Qtr.	0.9%	2.5%	4.5%	4.8%	6.4%
2nd Qtr.	3.2%	1.6%	4.5%	5.2%	6.8%
3rd Qtr.	2.3%	1.8%	4.6%	1.2%	1.2%
4th Qtr.	2.9%	1.7%	4.8%	6.4%	10.8%
2008					
1st Qtr.	-0.7%	-0.1%	4.9%	2.8%	9.6%
2nd Qtr.	0.6%	-0.2%	5.3%	7.6%	14.0%
3rd Qtr.	-4.0%	-1.7%	6.0%	2.8%	-0.4%
4th Qtr.	-6.8%	-6.7%	6.9%	-13.2%	-28.4%
2009					
1st Qtr.	-4.9%	-11.6%	8.1%	2.4%	-1.2%
2nd Qtr.	-0.7%	-12.9%	9.3%	3.6%	0.0%
3rd Qtr.	1.6%	-8.6%	9.6%	2.8%	9.6%
4th Qtr.	5.0%	-3.8%	10.0%	2.4%	-0.8%
					8.8%
2010					
1st Qtr.	3.7%	2.7%	9.7%	1.2%	6.4%
2nd Qtr.	1.7%	6.5%	9.7%	-1.6%	-3.6%
3rd Qtr.	2.6%	6.9%	9.6%	2.8%	4.0%
4th Qtr.	3.1%	6.4%	9.6%	2.8%	8.4%
2011					
1st Qtr.			8.9%		

Source: Council of Economic Advisors, Economic Indicators, various issues.

INTEREST RATES

Year	Prime Rate	US Treas T Bills 3 Month	US Treas T Bonds 10 Year	Utility Bonds Aaa	Utility Bonds Aa	Utility Bonds A	Utility Bonds Baa
			1975 - 1982 Cycle				
1975	7.86%	5.84%	7.99%	9.03%	9.44%	10.09%	10.96%
1976	6.84%	4.99%	7.61%	8.63%	8.92%	9.29%	9.82%
1977	6.83%	5.27%	7.42%	8.19%	8.43%	8.61%	9.06%
1978	9.06%	7.22%	8.41%	8.87%	9.10%	9.29%	9.62%
1979	12.67%	10.04%	9.44%	9.86%	10.22%	10.49%	10.96%
1980	15.27%	11.51%	11.46%	12.30%	13.00%	13.34%	13.95%
1981	18.89%	14.03%	13.93%	14.64%	15.30%	15.95%	16.60%
1982	14.86%	10.69%	13.00%	14.22%	14.79%	15.86%	16.45%
			1983 - 1991 Cycle				
1983	10.79%	8.63%	11.10%	12.52%	12.83%	13.66%	14.20%
1984	12.04%	9.58%	12.44%	12.72%	13.66%	14.03%	14.53%
1985	9.93%	7.48%	10.62%	11.68%	12.06%	12.47%	12.96%
1986	8.33%	5.98%	7.68%	8.92%	9.30%	9.58%	10.00%
1987	8.21%	5.82%	8.39%	9.52%	9.77%	10.10%	10.53%
1988	9.32%	6.69%	8.85%	10.05%	10.26%	10.49%	11.00%
1989	10.87%	8.12%	8.49%	9.32%	9.56%	9.77%	9.97%
1990	10.01%	7.51%	8.55%	9.45%	9.65%	9.86%	10.06%
1991	8.46%	5.42%	7.86%	8.85%	9.09%	9.36%	9.55%
			1992 - 2001 Cycle				
1992	6.25%	3.45%	7.01%	8.19%	8.55%	8.69%	8.86%
1993	6.00%	3.02%	5.87%	7.29%	7.44%	7.59%	7.91%
1994	7.15%	4.29%	7.09%	8.07%	8.21%	8.31%	8.63%
1995	8.83%	5.51%	6.57%	7.68%	7.77%	7.89%	8.29%
1996	8.27%	5.02%	6.44%	7.48%	7.57%	7.75%	8.16%
1997	8.44%	5.07%	6.35%	7.43%	7.54%	7.60%	7.95%
1998	8.35%	4.81%	5.26%	6.77%	6.91%	7.04%	7.26%
1999	8.00%	4.66%	5.65%	7.21%	7.51%	7.62%	7.88%
2000	9.23%	5.85%	6.03%	7.88%	8.06%	8.24%	8.36%
2001	6.91%	3.44%	5.02%	7.47%	7.59%	7.78%	8.02%
			2002 - 2009 Cycle				
2002	4.67%	1.62%	4.61%	[1]	7.19%	7.37%	8.02%
2003	4.12%	1.01%	4.01%		6.40%	6.58%	6.84%
2004	4.34%	1.38%	4.27%		6.04%	6.16%	6.40%
2005	6.19%	3.16%	4.29%		5.44%	5.65%	5.93%
2006	7.96%	4.73%	4.80%		5.84%	6.07%	6.32%
2007	8.05%	4.41%	4.63%		5.94%	6.07%	6.33%
2008	5.09%	1.48%	3.66%		6.18%	6.53%	7.25%
2009	3.25%	0.16%	3.26%		5.75%	6.04%	7.06%
			Current Cycle				
2010	3.25%	0.14%	3.22%		5.24%	5.46%	5.96%

[1] Note: Moody's has not published Aaa utility bond yields since 2001.

Sources: Council of Economic Advisors, Economic Indicators; Moody's Bond Record; Federal Reserve Bulletin; various issues.

INTEREST RATES

Year	Prime Rate	US Treas T Bills 3 Month	US Treas T Bonds 10 Year	Utility Bonds Aaa [1]	Utility Bonds Aa	Utility Bonds A	Utility Bonds Baa
2006							
Jan	7.50%	4.20%	4.42%		5.50%	5.75%	6.06%
Feb	7.50%	4.41%	4.57%		5.55%	5.82%	6.11%
Mar	7.75%	4.51%	4.72%		5.71%	5.98%	6.26%
Apr	7.75%	4.59%	4.99%		6.02%	6.29%	6.54%
May	8.00%	4.72%	5.11%		6.16%	6.42%	6.59%
June	8.25%	4.79%	5.11%		6.16%	6.40%	6.61%
July	8.25%	4.96%	5.09%		6.13%	6.37%	6.61%
Aug	8.25%	4.98%	4.88%		5.97%	6.20%	6.43%
Sept	8.25%	4.82%	4.72%		5.81%	6.00%	6.26%
Oct	8.25%	4.89%	4.73%		5.80%	5.98%	6.24%
Nov	8.25%	4.95%	4.60%		5.61%	5.80%	6.04%
Dec	8.25%	4.85%	4.56%		5.62%	5.81%	6.05%
2007							
Jan	8.25%	4.96%	4.76%		5.78%	5.96%	6.16%
Feb	8.25%	5.02%	4.72%		5.73%	5.90%	6.10%
Mar	8.25%	4.97%	4.56%		5.66%	5.85%	6.10%
Apr	8.25%	4.88%	4.69%		5.83%	5.97%	6.24%
May	8.25%	4.77%	4.75%		5.86%	5.99%	6.23%
June	8.25%	4.63%	5.10%		6.18%	6.30%	6.54%
July	8.25%	4.84%	5.00%		6.11%	6.25%	6.49%
Aug	8.25%	4.34%	4.67%		6.11%	6.24%	6.51%
Sept	7.75%	4.01%	4.52%		6.10%	6.18%	6.45%
Oct	7.50%	3.97%	4.53%		6.04%	6.11%	6.36%
Nov	7.50%	3.49%	4.15%		5.87%	5.97%	6.27%
Dec	7.25%	3.08%	4.10%		6.03%	6.16%	6.51%
2008							
Jan	6.00%	2.86%	3.74%		5.87%	6.02%	6.35%
Feb	6.00%	2.21%	3.74%		6.04%	6.21%	6.60%
Mar	5.25%	1.38%	3.51%		5.99%	6.21%	6.68%
Apr	5.00%	1.32%	3.68%		5.99%	6.29%	6.82%
May	5.00%	1.71%	3.88%		6.07%	6.27%	6.79%
June	5.00%	1.90%	4.10%		6.19%	6.38%	6.93%
July	5.00%	1.72%	4.01%		6.13%	6.40%	6.97%
Aug	5.00%	1.79%	3.89%		6.09%	6.37%	6.98%
Sept	5.00%	1.46%	3.69%		6.13%	6.49%	7.15%
Oct	4.00%	0.84%	3.81%		6.95%	7.56%	8.58%
Nov	4.00%	0.30%	3.53%		6.83%	7.60%	8.98%
Dec	3.25%	0.04%	2.42%		5.93%	6.54%	8.13%
2009							
Jan	3.25%	0.12%	2.52%		6.01%	6.39%	7.90%
Feb	3.25%	0.31%	2.87%		6.11%	6.30%	7.74%
Mar	3.25%	0.25%	2.82%		6.14%	6.42%	8.00%
Apr	3.25%	0.17%	2.93%		6.20%	6.48%	8.03%
May	3.25%	0.15%	3.29%		6.23%	6.49%	7.76%
June	3.25%	0.17%	3.72%		6.13%	6.20%	7.30%
July	3.25%	0.19%	3.56%		5.63%	5.97%	6.87%
Aug	3.25%	0.18%	3.59%		5.33%	5.71%	6.36%
Sept	3.25%	0.13%	3.40%		5.15%	5.53%	6.12%
Oct	3.25%	0.08%	3.39%		5.23%	5.55%	6.14%
Nov	3.25%	0.05%	3.40%		5.33%	5.64%	6.18%
Dec	3.25%	0.07%	3.59%		5.52%	5.79%	6.26%
2010							
Jan	3.25%	0.06%	3.73%		5.55%	5.77%	6.16%
Feb	3.25%	0.10%	3.69%		5.69%	5.87%	6.25%
Mar	3.25%	0.15%	3.73%		5.64%	5.84%	6.22%
Apr	3.25%	0.15%	3.85%		5.62%	5.81%	6.19%
May	3.25%	0.16%	3.42%		5.29%	5.50%	5.97%
June	3.25%	0.12%	3.20%		5.22%	5.46%	6.18%
July	3.25%	0.16%	3.01%		4.99%	5.26%	5.98%
Aug	3.25%	0.15%	2.70%		4.75%	5.01%	5.55%
Sept	3.25%	0.15%	2.65%		4.74%	5.01%	5.53%
Oct	3.25%	0.13%	2.54%		4.89%	5.10%	5.62%
Nov	3.25%	0.13%	2.76%		5.12%	5.37%	5.85%
Dec	3.25%	0.15%	3.29%		5.32%	5.56%	6.04%
2011							
Jan	3.25%	0.15%	3.39%		5.29%	5.57%	6.06%
Feb	3.25%	0.14%	3.58%		5.42%	5.68%	6.10%
Mar	3.25%	0.11%	3.41%		5.33%	5.56%	5.97%
Apr	3.25%						

[1] Note: Moody's has not published Aaa utility bond yields since 2001.

Sources: Council of Economic Advisors, Economic Indicators; Moody's Bond Record; Federal Reserve Bulletin; various issues.

STOCK PRICE INDICATORS

Year	S&P Composite [1]	NASDAQ Composite [1]	DJIA	S&P D/P	S&P E/P
		1975 - 1982 Cycle			
1975			802.49	4.31%	9.15%
1976			974.92	3.77%	8.90%
1977			894.63	4.62%	10.79%
1978			820.23	5.28%	12.03%
1979			844.40	5.47%	13.46%
1980			891.41	5.26%	12.66%
1981			932.92	5.20%	11.96%
1982			884.36	5.81%	11.60%
		1983 - 1991 Cycle			
1983			1,190.34	4.40%	8.03%
1984			1,178.48	4.64%	10.02%
1985			1,328.23	4.25%	8.12%
1986			1,792.76	3.49%	6.09%
1987			2,275.99	3.08%	5.48%
1988	[1]	[1]	2,060.82	3.64%	8.01%
1989	322.84		2,508.91	3.45%	7.41%
1990	334.59		2,678.94	3.61%	6.47%
1991	376.18	491.69	2,929.33	3.24%	4.79%
		1992 - 2001 Cycle			
1992	415.74	599.26	3,284.29	2.99%	4.22%
1993	451.21	715.16	3,522.06	2.78%	4.46%
1994	460.42	751.65	3,793.77	2.82%	5.83%
1995	541.72	925.19	4,493.76	2.56%	6.09%
1996	670.50	1,164.96	5,742.89	2.19%	5.24%
1997	873.43	1,469.49	7,441.15	1.77%	4.57%
1998	1,085.50	1,794.91	8,625.52	1.49%	3.46%
1999	1,327.33	2,728.15	10,464.88	1.25%	3.17%
2000	1,427.22	3,783.67	10,734.90	1.15%	3.63%
2001	1,194.18	2,035.00	10,189.13	1.32%	2.95%
		2002 - 2009 Cycle			
2002	993.94	1,539.73	9,226.43	1.61%	2.92%
2003	965.23	1,647.17	8,993.59	1.77%	3.84%
2004	1,130.65	1,986.53	10,317.39	1.72%	4.89%
2005	1,207.23	2,099.32	10,547.67	1.83%	5.36%
2006	1,310.46	2,263.41	11,408.67	1.87%	5.78%
2007	1,477.19	2,578.47	13,169.98	1.86%	5.29%
2008	1,220.04	2,161.65	11,252.62	2.37%	3.54%
2009	948.05	1,845.38	8,876.15	2.40%	1.86%
		Current Cycle			
2010	1,139.97	2,349.89	10,662.80	1.98%	6.04%

[1] Note: this source did not publish the S&P Composite prior to 1988 and the NASDAQ Composite prior to 1991.

Source: Council of Economic Advisors, Economic Indicators, various issues.

STOCK PRICE INDICATORS

YEAR	S&P Composite	NASDAQ Composite	DJIA	S&P D/P	S&P E/P
2004					
1st Qtr.	1,133.29	2,041.95	10,488.43	1.64%	4.62%
2nd Qtr.	1,122.87	1,984.13	10,289.04	1.71%	4.92%
3rd Qtr.	1,104.15	1,872.90	10,129.85	1.79%	5.18%
4th Qtr.	1,162.07	2,050.22	10,362.25	1.75%	4.83%
2005					
1st Qtr.	1,191.98	2,056.01	10,648.48	1.77%	5.11%
2nd Qtr.	1,181.65	2,012.24	10,382.35	1.85%	5.32%
3rd Qtr.	1,225.91	2,144.61	10,532.24	1.83%	5.42%
4th Qtr.	1,262.07	2,246.09	10,827.79	1.86%	5.60%
2006					
1st Qtr.	1,283.04	2,287.97	10,996.04	1.85%	5.61%
2nd Qtr.	1,281.77	2,240.46	11,188.84	1.90%	5.86%
3rd Qtr.	1,288.40	2,141.97	11,274.49	1.91%	5.88%
4th Qtr.	1,389.48	2,390.26	12,175.30	1.81%	5.75%
2007					
1st Qtr.	1,425.30	2,444.85	12,470.97	1.84%	5.85%
2nd Qtr.	1,496.43	2,552.37	13,214.26	1.82%	5.65%
3rd Qtr.	1,490.81	2,609.68	13,488.43	1.86%	5.15%
4th Qtr.	1,494.09	2,701.59	13,502.95	1.91%	4.51%
2008					
1st Qtr.	1,350.19	2,332.91	12,383.86	2.11%	4.55%
2nd Qtr.	1,371.65	2,426.26	12,508.59	2.10%	4.01%
3rd Qtr.	1,251.94	2,290.87	11,322.40	2.29%	3.94%
4th Qtr.	909.80	1,599.64	8,795.61	2.98%	1.65%
2009					
1st Qtr.	809.31	1,485.14	7,774.06	3.00%	0.86%
2nd Qtr.	892.23	1,731.41	8,327.83	2.45%	0.82%
3rd Qtr.	996.68	1,985.25	9,229.93	2.16%	1.19%
4th Qtr.	1,088.70	2,162.33	10,172.78	1.99%	4.57%
2010					
1st Qtr.	1,121.60	2,274.82	10,454.42	1.94%	5.21%
2nd Qtr.	1,135.25	2,343.40	10,570.54	1.97%	6.51%
3rd Qtr.	1,096.39	2,237.97	10,390.24	2.09%	6.30%
4th Qtr.	1,204.00	2,534.62	11,236.02	1.95%	6.15%
2011					
1st Qtr.	1,302.74	2,741.01	12,024.62	1.85%	

[1] Note: this source did not publish the S&P Composite prior to 1988 and the NASDA(*Composite prior to 1991.*

Source: Council of Economic Advisors, Economic Indicators, various issues.

Exhibit___(DCP-1)
Schedule 3

SOUTHWEST GAS CORPORATION
UNSECURED DEBT RATINGS

Date	Moody's	S&P	Fitch
2001	Baa2	BBB-	BBB
2002	Baa2	BBB-	BBB
2003	Baa2	BBB-	BBB
2004	Baa2	BBB-	BBB
2005	Baa2	BBB-	BBB
2006	Baa2	BBB-	BBB
2007	Baa3	BBB-	BBB
2008	Baa3	BBB-	BBB
2009	Baa3	BBB	BBB
2010	Baa2	BBB	BBB
2011	Baa2	BBB	BBB

Source: Response to ACC-STF-2-4.

SOUTHWEST GAS CORPORATION
CAPITAL STRUCTURE RATIOS
1995 - 2010
($000)

YEAR	COMMON EQUITY	PREFERRED STOCK	LONG-TERM DEBT	SHORT-TERM DEBT
1995	$356,050 30.1% 31.1%	$60,000	$727,945 61.6% 63.6%	$37,000 3.1%
1996	$379,616 30.8% 34.2%	$60,000	$671,896 54.5% 60.4%	$121,000 9.8%
1997	$385,979 28.1% 31.4%	$60,000	$784,314 57.2% 63.8%	$142,000 10.3%
1998	$476,400 33.9% 35.2%	$60,000	$818,176 58.2% 60.4%	$52,000 3.7%
1999	$505,425 33.8% 35.3%	$60,000	$867,222 58.1% 60.5%	$61,000 4.1%
2000	$533,467 32.7% 35.6%	$60,000	$904,556 55.5% 60.4%	$131,000 8.0%
2001	$561,200 30.9% 32.5%	$60,000	$1,103,992 60.7% 64.0%	$93,000 5.1%
2002	$596,167 32.9% 33.9%	$60,000 3.3% 3.4%	$1,100,853 60.8% 62.7%	$53,000 2.9%
2003	$630,467 33.0% 33.9%	$100,000 5.2% 5.4%	$1,127,599 59.0% 60.7%	$52,000 2.7%
2004	$705,676 33.6% 35.3%	$100,000 4.8% 5.0%	$1,192,757 56.8% 59.7%	$100,000 4.8%
2005	$751,135 34.4% 34.8%	$100,000 4.6% 4.6%	$1,308,113 59.9% 60.6%	$24,000 1.1%
2006	$901,425 38.9% 38.9%	$100,000 4.3% 4.3%	$1,313,899 56.7% 56.7%	$0 0.0%
2007	$983,673 41.0% 41.2%	$100,000 4.2% 4.2%	$1,304,146 54.4% 54.6%	$9,000 0.4%
2008	$1,037,841 43.5% 44.5%	$100,000 4.2% 4.3%	$1,193,307 50.0% 51.2%	$55,000 2.3%
2009	$1,102,086 46.4% 46.4%	$100,000 4.2% 4.2%	$1,170,684 49.3% 49.3%	$0 0.0%
2010	$1,166,996 49.3% 50.9%	$0 0.0% 0.0%	$1,124,681 47.5% 49.1%	$75,080 3.2%

Note: Percentages may not total 100.0% due to rounding.

Source: Response to ACC-STF-2-17 and 2010 Annual Report of Southwest Gas.

SOUTHWEST GAS CORPORATION
CAPITAL STRUCTURE RATIOS
1995 - 2010
($000)

YEAR	COMMON EQUITY	PREFERRED STOCK	LONG-TERM DEBT	SHORT-TERM DEBT
1995	$356,050 30.1% 31.1%	$60,000	$727,945 61.6% 63.6%	$37,000 3.1%
1996	$379,616 30.8% 34.2%	$60,000	$671,896 54.5% 60.4%	$121,000 9.8%
1997	$385,979 28.1% 31.4%	$60,000	$784,314 57.2% 63.8%	$142,000 10.3%
1998	$476,400 33.9% 35.2%	$60,000	$818,176 58.2% 60.4%	$52,000 3.7%
1999	$505,425 33.8% 35.3%	$60,000	$867,222 58.1% 60.5%	$61,000 4.1%
2000	$533,467 32.7% 35.6%	$60,000	$904,556 55.5% 60.4%	$131,000 8.0%
2001	$561,200 30.9% 32.5%	$60,000	$1,103,992 60.7% 64.0%	$93,000 5.1%
2002	$596,167 32.9% 33.9%	$60,000 3.3% 3.4%	$1,100,853 60.8% 62.7%	$53,000 2.9%
2003	$630,467 33.0% 33.9%	$100,000 5.2% 5.4%	$1,127,599 59.0% 60.7%	$52,000 2.7%
2004	$705,676 33.6% 35.3%	$100,000 4.8% 5.0%	$1,192,757 56.8% 59.7%	$100,000 4.8%
2005	$751,135 34.4% 34.8%	$100,000 4.6% 4.6%	$1,308,113 59.9% 60.6%	$24,000 1.1%
2006	$901,425 38.9% 38.9%	$100,000 4.3% 4.3%	$1,313,899 56.7% 56.7%	$0 0.0%
2007	$983,673 41.0% 41.2%	$100,000 4.2% 4.2%	$1,304,146 54.4% 54.6%	$9,000 0.4%
2008	$1,037,841 43.5% 44.5%	$100,000 4.2% 4.3%	$1,193,307 50.0% 51.2%	$55,000 2.3%
2009	$1,102,086 46.4% 46.4%	$100,000 4.2% 4.2%	$1,170,684 49.3% 49.3%	$0 0.0%
2010	$1,166,996 49.3% 50.9%	$0 0.0% 0.0%	$1,124,681 47.5% 49.1%	$75,080 3.2%

Note: Percentages may not total 100.0% due to rounding.

Source: Response to ACC-STF-2-17 and 2010 Annual Report of Southwest Gas.

PROXY GROUP OF GAS DISTRIBUTION COMPANIES
COMMON EQUITY RATIOS

COMPANY	2006	2007	2008	2009	2010	Average
AGL Resources	49.8%	49.8%	49.7%	47.4%	56.0%	50.5%
Atmos Energy	43.0%	48.0%	49.2%	50.1%	55.0%	49.1%
Laclede Group	50.4%	54.6%	55.5%	57.1%	60.0%	55.5%
Northwest Natural Gas	53.7%	53.7%	55.1%	52.3%	54.0%	53.8%
Piedmont Natural Gas	51.7%	51.6%	52.8%	55.9%	55.0%	53.4%
South Jersey Industries	55.3%	57.3%	60.8%	63.5%	65.5%	60.5%
Southwest Gas	39.4%	41.9%	44.7%	46.5%	51.0%	44.7%
WGL Holdings	60.4%	60.3%	62.4%	65.0%	65.0%	62.6%
Average	50.5%	52.2%	53.8%	54.7%	57.7%	51.3%

Source: Value Line Investment Survey.

PROXY GROUP OF GAS DISTRIBUTION COMPANIES
CAPITAL STRUCTURE RATIOS
INCLUDING SHORT-TERM DEBT

Company	2006	2007	2008	2009	2010
AGL Resources	42%	42%	39%	41%	40%
Atmos Energy	45%	47%	46%	51%	49%
Laclede Group	58%	40%	44%	50%	54%
Northwest Natural Gas	48%	47%	45%	47%	45%
Piedmont Natural Gas	47%	45%	43%	48%	49%
South Jersey Industries	44%	50%	47%	50%	45%
Southwest Gas	41%	43%	43%	46%	49%
WGL Holdings	51%	51%	50%	56%	60%
Average	**47%**	**46%**	**45%**	**49%**	**49%**

Source: AUS Utility Reports.

Exhibit___(DCP-1)
Schedule 6

SELECTION OF PROXY COMPANIES

Company	Percent Reg Gas Revenues	S&P Bond Rating	Moody's Bond Rating	Common Equity Ratio	Value Line Safety
Value Line Natural Gas Utility Group					
AGL Resources	63%	A-	A3	40%	2
Atmos Energy	65%	BBB+	Baa2	49%	2
Laclede Group	51%	A	A2	54%	2
New Jersey Resources	**36%**	A+	NR	48%	1
NICOR	81%	AA	Aa3	55%	3
Northwest Natural Gas	94%	A+	A1	45%	1
Piedmont Natural Gas	100%	A	A3	49%	2
South Jersey Industries	51%	A	A2	45%	2
Southwest Gas	83%	BBB	Baa3	49%	3
UGI	**34%**	NR	A3	**39%**	2
WGL Holdings	49%	AA-	A2	60%	1

Note: Figures as of year-end 2010.

Sources: AUS Utility Reports, Value Line.

PROXY COMPANIES
DIVIDEND YIELD

COMPANY	Qtr. DPS	February - April, 2011 DPS	HIGH	LOW	AVERAGE	YIELD
Proxy Group of Natural Gas Distribution Companies						
AGL Resources	$0.450	$1.80	$41.61	$36.82	$39.22	4.6%
Atmos Energy	$0.340	$1.36	$35.25	$32.24	$33.75	4.0%
Laclede Group	$0.405	$1.62	$39.50	$36.30	$37.90	4.3%
Northwest Natural Gas	$0.435	$1.74	$48.72	$44.07	$46.40	3.8%
Piedmont Natural Gas	$0.290	$1.16	$32.00	$27.88	$29.94	3.9%
South Jersey Industries	$0.365	$1.46	$58.03	$52.18	$55.11	2.6%
Southwest Gas	$0.250	$1.00	$39.89	$36.97	$38.43	2.6%
WGL Holdings	$0.388	$1.55	$39.68	$36.09	$37.89	4.1%
Average						**3.7%**
Hevert Proxy Group						
AGL Resources	$0.450	$1.80	$41.61	$36.82	$39.22	4.6%
Atmos Energy	$0.340	$1.36	$35.25	$32.24	$33.75	4.0%
Laclede Group	$0.405	$1.62	$39.50	$36.30	$37.90	4.3%
New Jersey Resources	$0.360	$1.44	$44.10	$40.24	$42.17	3.4%
Nicor	$0.465	$1.86	$55.50	$50.58	$53.04	3.5%
Northwest Natural Gas	$0.435	$1.74	$48.72	$44.07	$46.40	3.8%
Piedmont Natural Gas	$0.290	$1.16	$32.00	$27.88	$29.94	3.9%
South Jersey Industries	$0.365	$1.46	$58.03	$52.18	$55.11	2.6%
WGL Holdings	$0.388	$1.55	$39.68	$36.09	$37.89	4.1%
Average						**3.8%**

Source: Yahoo! Finance.

PROXY COMPANIES
RETENTION GROWTH RATES

COMPANY	2006	2007	2008	2009	2010	Average	2011	2012	2014-'16	Average
Proxy Group of Natural Gas Distribution Companies										
AGL Resources	6.3%	5.3%	5.1%	5.3%	5.6%	5.5%	6.5%	5.5%	6.0%	6.0%
Atmos Energy	3.6%	3.0%	3.1%	2.7%	3.5%	3.2%	3.5%	3.5%	4.0%	3.7%
Laclede Group	5.1%	4.3%	5.2%	5.9%	3.6%	4.8%	4.0%	4.0%	4.5%	4.2%
Northwest Natural Gas	4.5%	6.0%	4.5%	5.0%	4.0%	4.8%	4.0%	4.0%	4.0%	4.0%
Piedmont Natural Gas	2.8%	3.5%	3.9%	4.8%	3.3%	3.7%	3.5%	3.5%	4.0%	3.7%
South Jersey Industries	10.2%	6.7%	6.7%	6.4%	7.1%	7.4%	7.0%	8.5%	9.0%	8.2%
Southwest Gas	5.2%	4.8%	2.1%	4.1%	5.0%	4.2%	5.0%	5.0%	5.5%	5.2%
WGL Holdings	3.2%	3.5%	5.0%	5.0%	3.3%	4.0%	2.5%	3.0%	3.5%	3.0%
Average						**4.7%**				**4.7%**
Hevert Proxy Group										
AGL Resources	6.3%	5.3%	5.1%	5.3%	5.6%	5.5%	6.5%	5.5%	6.0%	6.0%
Atmos Energy	3.6%	3.0%	3.1%	2.7%	3.5%	3.2%	3.5%	3.5%	4.0%	3.7%
Laclede Group	5.1%	4.3%	5.2%	5.9%	3.6%	4.8%	4.0%	4.0%	4.5%	4.2%
New Jersey Resources	6.3%	3.6%	9.5%	7.2%	6.8%	6.7%	6.5%	7.0%	6.5%	6.7%
Nicor	5.2%	5.4%	3.6%	4.9%	3.2%	4.5%	4.0%	4.0%	3.5%	3.8%
Northwest Natural Gas	4.5%	6.0%	4.5%	5.0%	4.0%	4.8%	4.0%	4.0%	4.0%	4.0%
Piedmont Natural Gas	2.8%	3.5%	3.9%	4.8%	3.3%	3.7%	3.5%	3.5%	4.0%	3.7%
South Jersey Industries	10.2%	6.7%	6.7%	6.4%	7.1%	7.4%	7.0%	8.5%	9.0%	8.2%
WGL Holdings	3.2%	3.5%	5.0%	5.0%	3.3%	4.0%	2.5%	3.0%	3.5%	3.0%
Average						**4.9%**				**4.8%**

Source: Value Line Investment Survey.

PROXY COMPANIES
PER SHARE GROWTH RATES

COMPANY	5-Year Historic Growth Rates EPS	DPS	BVPS	Average	Est'd '08-'10 to '14-'16 Growth Rates EPS	DPS	BVPS	Average
Proxy Group of Natural Gas Distribution Companies								
AGL Resources	4.5%	7.5%	5.5%	5.8%	4.5%	2.0%	5.5%	4.0%
Atmos Energy	4.0%	1.5%	5.0%	3.5%	5.0%	2.0%	4.5%	3.8%
Laclede Group	7.5%	2.5%	7.0%	5.7%	3.0%	2.5%	5.0%	3.5%
Northwest Natural Gas	9.5%	3.5%	4.0%	5.7%	3.0%	4.0%	4.0%	3.7%
Piedmont Natural Gas	5.0%	4.5%	3.5%	4.3%	3.5%	3.5%	3.0%	3.3%
South Jersey Industries	10.0%	7.5%	9.0%	8.8%	9.0%	8.5%	4.5%	7.3%
Southwest Gas	6.0%	2.0%	5.0%	4.3%	7.5%	4.5%	4.5%	5.5%
WGL Holdings	2.5%	2.5%	5.0%	3.3%	1.5%	2.5%	4.0%	2.7%
Average				**5.2%**				**4.2%**
Hevert Proxy Group								
AGL Resources	4.5%	7.5%	5.5%	5.8%	4.5%	2.0%	5.5%	4.0%
Atmos Energy	4.0%	1.5%	5.0%	3.5%	5.0%	2.0%	4.5%	3.8%
Laclede Group	7.5%	2.5%	7.0%	5.7%	3.0%	2.5%	5.0%	3.5%
New Jersey Resources	8.5%	7.5%	10.0%	8.7%	4.0%	4.5%	5.5%	4.7%
Nicor	3.5%	0.0%	5.0%	2.8%	-0.5%	0.0%	4.0%	1.2%
Northwest Natural Gas	9.5%	3.5%	4.0%	5.7%	3.0%	4.0%	4.0%	3.7%
Piedmont Natural Gas	5.0%	4.5%	3.5%	4.3%	3.5%	3.5%	3.0%	3.3%
South Jersey Industries	10.0%	7.5%	9.0%	8.8%	9.0%	8.5%	4.5%	7.3%
WGL Holdings	2.5%	2.5%	5.0%	3.3%	1.5%	2.5%	4.0%	2.7%
Average				**5.4%**				**3.8%**

Source: Value Line Investment Survey.

PROXY COMPANIES
DCF COST RATES

COMPANY	ADJUSTED YIELD	HISTORIC RETENTION GROWTH	PROSPECTIVE RETENTION GROWTH	HISTORIC PER SHARE GROWTH	PROSPECTIVE PER SHARE GROWTH	FIRST CALL EPS GROWTH	AVERAGE GROWTH	DCF RATES
Proxy Group of Natural Gas Distribution Companies								
AGL Resources	4.7%	5.5%	6.0%	5.8%	4.0%	5.6%	5.4%	10.1%
Atmos Energy	4.1%	3.2%	3.7%	3.5%	3.8%	3.6%	3.6%	7.7%
Laclede Group	4.4%	4.8%	4.2%	5.7%	3.5%	3.5%	4.3%	8.7%
Northwest Natural Gas	3.8%	4.8%	4.0%	5.7%	3.7%	3.9%	4.4%	8.2%
Piedmont Natural Gas	3.9%	3.7%	3.7%	4.3%	3.3%	3.6%	3.7%	7.7%
South Jersey Industries	2.8%	7.4%	8.2%	8.8%	7.3%	6.3%	7.6%	10.4%
Southwest Gas	2.7%	4.2%	5.2%	4.3%	5.5%	4.4%	4.7%	7.4%
WGL Holdings	4.2%	4.0%	3.0%	3.3%	2.7%	3.9%	3.4%	7.5%
Mean	3.8%	4.7%	4.7%	5.2%	4.2%	4.4%	4.6%	**8.5%**
Median	4.0%	4.5%	4.1%	5.0%	3.8%	3.9%	4.4%	**8.0%**
Composite - Mean		8.5%	8.5%	**9.0%**	**8.0%**	8.2%	8.5%	
Composite - Median		8.5%	8.1%	**9.0%**	**7.8%**	7.9%	8.4%	
Hevert Proxy Group								
AGL Resources	4.7%	5.5%	6.0%	5.8%	4.0%	5.6%	5.4%	10.1%
Atmos Energy	4.1%	3.2%	3.7%	3.5%	3.8%	3.6%	3.6%	7.7%
Laclede Group	4.4%	4.8%	4.2%	5.7%	3.5%	3.5%	4.3%	8.7%
New Jersey Resources	3.5%	6.7%	6.7%	8.7%	4.7%	2.5%	5.8%	9.3%
Nicor	3.5%	4.5%	3.8%	2.8%	1.2%	-0.2%	2.4%	6.0%
Northwest Natural Gas	3.8%	4.8%	4.0%	5.7%	3.7%	3.9%	4.4%	8.2%
Piedmont Natural Gas	3.9%	3.7%	3.7%	4.3%	3.3%	3.6%	3.7%	7.7%
South Jersey Industries	2.8%	7.4%	8.2%	8.8%	7.3%	6.3%	7.6%	10.4%
WGL Holdings	4.2%	4.0%	3.0%	3.3%	2.7%	3.9%	3.4%	7.5%
Mean	3.9%	4.9%	4.8%	5.4%	3.8%	3.6%	4.5%	**8.4%**
Median	3.9%	4.8%	4.0%	5.7%	3.7%	3.6%	4.3%	**8.2%**
Composite - Mean		8.8%	8.7%	**9.3%**	7.7%	**7.5%**	8.4%	
Composite - Median		8.7%	7.9%	**9.6%**	7.6%	**7.5%**	8.3%	

Sources: Prior pages of this schedule.

PROXY COMPANIES
CAPM COST RATES

COMPANY	RISK-FREE RATE	BETA	RISK PREMIUM	CAPM RATES
Proxy Group of Natural Gas Distribution Companies				
AGL Resources	4.32%	0.75	5.54%	8.5%
Atmos Energy	4.32%	0.65	5.54%	7.9%
Laclede Group	4.32%	0.60	5.54%	7.6%
Northwest Natural Gas	4.32%	0.60	5.54%	7.6%
Piedmont Natural Gas	4.32%	0.65	5.54%	7.9%
South Jersey Industries	4.32%	0.65	5.54%	7.9%
Southwest Gas	4.32%	0.75	5.54%	8.5%
WGL Holdings	4.32%	0.65	5.54%	7.9%
Mean				**8.0%**
Median				**7.9%**
Hevert Proxy Group				
AGL Resources	4.32%	0.75	5.54%	8.5%
Atmos Energy	4.32%	0.65	5.54%	7.9%
Laclede Group	4.32%	0.60	5.54%	7.6%
New Jersey Resources	4.32%	0.65	5.54%	7.9%
Nicor	4.32%	0.75	5.54%	8.5%
Northwest Natural Gas	4.32%	0.60	5.54%	7.6%
Piedmont Natural Gas	4.32%	0.65	5.54%	7.9%
South Jersey Industries	4.32%	0.65	5.54%	7.9%
WGL Holdings	4.32%	0.65	5.54%	7.9%
Mean				**8.0%**
Median				**7.9%**

Sources: Value Line Investment Survey, Standard & Poor's Analysts' Handbook, Federal Reserve.

Yields on 20-Year U.S. Treasury Bonds:

Feb., 2011	4.42%
March, 2011	4.27%
April, 2011	4.28%
Average	**4.32%**

PROXY COMPANIES
RATES OF RETURN ON AVERAGE COMMON EQUITY

COMPANY	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	1992-2001 Average	2002-2010 Average	2011	2012	2014-16
Proxy Group of Natural Gas Distribution Companies																								
AGL Resources	11.8%	11.0%	11.6%	13.1%	13.2%	12.7%	12.6%	7.9%	11.2%	12.7%	14.7%	15.3%	13.9%	13.3%	13.6%	12.8%	12.5%	13.0%	12.7%	11.8%	13.5%	12.5%	12.5%	12.5%
Atmos Energy	10.7%	12.7%	10.0%	12.2%	14.4%	12.3%	15.8%	6.7%	8.5%	11.1%	10.3%	11.2%	9.1%	9.1%	10.0%	9.2%	9.0%	8.5%	9.1%	11.4%	9.5%	9.0%	8.5%	9.0%
Laclede Group	9.9%	13.4%	11.5%	10.0%	14.0%	13.2%	11.0%	10.0%	9.1%	10.6%	7.8%	11.8%	11.2%	11.1%	13.1%	12.0%	12.6%	12.9%	10.1%	11.3%	11.4%	10.5%	10.5%	10.0%
Northwest Natural Gas	6.0%	13.7%	12.2%	11.4%	13.2%	11.2%	6.3%	10.1%	10.2%	10.3%	8.7%	9.2%	9.3%	10.1%	10.9%	12.4%	11.1%	11.6%	10.9%	10.5%	10.5%	10.5%	10.5%	10.0%
Piedmont Natural Gas	14.1%	13.8%	12.2%	12.3%	13.2%	13.8%	13.6%	12.1%	12.5%	12.0%	10.8%	12.2%	12.4%	11.6%	11.0%	11.8%	12.4%	13.5%	11.8%	13.0%	11.9%	12.0%	12.0%	12.5%
South Jersey Industries	11.8%	11.0%	8.5%	11.4%	11.1%	11.9%	10.1%	15.6%	15.4%	15.3%	14.0%	13.1%	13.4%	13.2%	17.2%	13.3%	13.5%	13.4%	14.5%	12.2%	14.0%	15.0%	16.5%	17.5%
Southwest Gas	5.1%	3.9%	7.5%	0.6%	1.7%	5.4%	10.4%	7.5%	7.3%	6.7%	6.6%	6.2%	8.8%	6.5%	9.7%	8.8%	6.0%	8.1%	9.6%	5.6%	7.8%	9.0%	9.0%	9.0%
WGL Holdings	12.5%	12.1%	12.6%	12.4%	15.0%	14.1%	11.3%	10.3%	11.9%	11.9%	7.1%	14.4%	11.9%	12.1%	10.8%	11.0%	12.0%	11.8%	10.2%	12.4%	11.3%	9.0%	9.5%	10.0%
Average	10.2%	11.5%	10.8%	10.4%	12.0%	11.8%	11.4%	10.0%	10.8%	11.3%	10.0%	11.7%	11.3%	10.9%	12.0%	11.4%	11.1%	11.6%	11.1%	**11.0%**	**11.2%**	**10.9%**	**11.1%**	**11.3%**
Median	11.3%	12.4%	11.6%	11.8%	13.2%	12.5%	11.2%	10.1%	10.7%	11.5%	9.5%	12.0%	11.6%	11.4%	11.0%	11.9%	12.2%	12.4%	10.6%	**11.6%**	**11.4%**	**10.5%**	**10.5%**	**10.0%**
Hevert Proxy Group																								
AGL Resources	11.8%	11.0%	11.6%	13.1%	13.2%	12.7%	12.6%	7.9%	11.2%	12.7%	14.7%	15.3%	13.9%	13.3%	13.6%	12.8%	12.5%	13.0%	12.7%	11.8%	13.5%	12.5%	12.5%	12.5%
Atmos Energy	10.7%	12.7%	10.0%	12.2%	14.4%	12.3%	15.8%	6.7%	8.5%	11.1%	10.3%	11.2%	9.1%	9.1%	10.0%	9.2%	9.0%	8.5%	9.1%	11.4%	9.5%	9.0%	8.5%	9.0%
Laclede Group	9.9%	13.4%	11.5%	10.0%	14.0%	13.2%	11.0%	10.0%	9.1%	10.6%	7.8%	11.8%	11.2%	11.1%	13.1%	12.0%	12.6%	12.9%	10.1%	11.3%	11.4%	10.5%	10.5%	10.0%
New Jersey Resources	12.2%	11.8%	13.0%	13.3%	13.9%	14.5%	14.7%	15.0%	15.1%	15.2%	15.9%	16.8%	15.8%	16.2%	14.6%	10.2%	16.5%	14.2%	14.4%	13.9%	15.0%	14.5%	15.0%	13.5%
Nicor	15.3%	15.3%	15.7%	14.6%	17.0%	16.9%	14.7%	15.7%	18.2%	18.8%	17.3%	12.4%	13.0%	12.8%	15.2%	14.9%	12.5%	13.4%	11.8%	16.2%	13.7%	11.0%	11.0%	10.0%
Northwest Natural Gas	6.0%	13.7%	12.2%	11.4%	13.2%	11.2%	6.3%	10.1%	10.2%	10.3%	8.7%	9.2%	9.3%	10.1%	10.9%	12.4%	11.1%	11.6%	10.9%	10.5%	10.5%	10.5%	10.5%	10.0%
Piedmont Natural Gas	14.1%	13.8%	12.2%	12.3%	13.2%	13.8%	13.6%	12.1%	12.5%	12.0%	10.8%	12.2%	12.4%	11.6%	11.0%	11.8%	12.4%	13.5%	11.8%	13.0%	11.9%	12.0%	12.0%	12.5%
South Jersey Industries	11.8%	11.0%	8.5%	11.4%	11.1%	11.9%	10.1%	15.6%	15.4%	15.3%	14.0%	13.1%	13.4%	13.2%	17.2%	13.3%	13.5%	13.4%	14.5%	12.2%	14.0%	15.0%	16.5%	17.5%
WGL Holdings	12.5%	12.1%	12.6%	12.4%	15.0%	14.1%	11.3%	10.3%	11.9%	11.9%	7.1%	14.4%	11.9%	12.1%	10.8%	11.0%	12.0%	11.8%	10.2%	12.4%	11.3%	9.0%	9.5%	10.0%
Average	11.6%	12.8%	11.9%	12.3%	13.9%	13.4%	12.2%	11.5%	12.5%	13.1%	11.8%	12.9%	12.2%	12.2%	12.9%	12.0%	12.5%	12.5%	11.7%	**12.5%**	**12.3%**	**11.6%**	**11.8%**	**11.7%**
Median	11.8%	12.7%	12.2%	12.3%	13.9%	13.2%	12.6%	10.3%	11.9%	12.0%	10.8%	12.4%	12.4%	12.1%	13.1%	12.0%	12.5%	13.0%	11.8%	**12.3%**	**12.2%**	**11.0%**	**11.0%**	**10.0%**

Source: Calculations made from data contained in Value Line Investment Survey.

PROXY COMPANIES
MARKET TO BOOK RATIOS

COMPANY	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	1992-2001 Average	2002-2010 Average
Proxy Group of Natural Gas Distribution Companies																					
AGL Resources	181%	195%	169%	172%	189%	183%	183%	169%	168%	184%	171%	188%	184%	191%	186%	188%	146%	138%	158%	179%	172%
Atmos Energy	158%	194%	186%	196%	248%	241%	246%	216%	167%	170%	150%	152%	147%	145%	146%	136%	110%	109%	119%	202%	135%
Laclede Group	158%	187%	178%	163%	168%	175%	174%	159%	141%	155%	145%	169%	179%	179%	184%	168%	209%	171%	138%	166%	171%
Northwest Natural Gas	162%	176%	161%	146%	156%	173%	169%	141%	129%	133%	145%	144%	153%	172%	177%	208%	201%	173%	182%	155%	173%
Piedmont Natural Gas	180%	214%	186%	182%	183%	217%	222%	213%	195%	199%	186%	211%	212%	208%	221%	210%	237%	213%	212%	199%	212%
South Jersey Industries	154%	175%	141%	142%	146%	178%	209%	202%	196%	205%	185%	170%	195%	221%	209%	231%	196%	204%	241%	175%	206%
Southwest Gas	81%	100%	103%	103%	121%	129%	139%	147%	120%	127%	123%	118%	127%	135%	161%	149%	117%	97%	127%	117%	128%
WGL Holdings	173%	189%	165%	164%	178%	199%	197%	176%	177%	177%	152%	162%	175%	183%	168%	172%	146%	149%	159%	180%	163%
Average	156%	179%	161%	159%	174%	187%	192%	178%	162%	169%	157%	164%	172%	179%	182%	183%	170%	157%	167%	**172%**	**170%**
Median	160%	188%	167%	164%	173%	181%	190%	173%	168%	174%	151%	166%	177%	181%	181%	180%	171%	160%	159%	**174%**	**169%**
Hevert Proxy Group																					
AGL Resources	181%	195%	169%	172%	189%	183%	183%	169%	168%	184%	171%	188%	184%	191%	186%	188%	146%	138%	158%	179%	172%
Atmos Energy	158%	194%	186%	196%	248%	241%	246%	216%	167%	170%	150%	152%	147%	145%	146%	136%	110%	109%	119%	202%	135%
Laclede Group	158%	187%	178%	163%	168%	175%	174%	159%	141%	155%	145%	169%	179%	179%	184%	168%	209%	171%	138%	166%	171%
New Jersey Resources	161%	186%	162%	178%	191%	229%	225%	224%	226%	224%	220%	245%	251%	275%	246%	223%	200%	214%	227%	216%	233%
Nicor	179%	216%	195%	187%	220%	242%	260%	226%	227%	239%	199%	185%	210%	222%	234%	229%	200%	159%	186%	219%	203%
Northwest Natural Gas	162%	176%	161%	146%	156%	173%	169%	141%	129%	133%	145%	144%	153%	172%	177%	208%	201%	173%	182%	155%	173%
Piedmont Natural Gas	180%	214%	186%	182%	183%	217%	222%	213%	195%	199%	186%	211%	212%	208%	221%	210%	237%	213%	212%	199%	212%
South Jersey Industries	154%	175%	141%	142%	146%	178%	209%	202%	196%	205%	185%	170%	195%	221%	209%	231%	196%	204%	241%	175%	206%
WGL Holdings	173%	189%	165%	164%	178%	199%	197%	176%	177%	177%	152%	162%	175%	183%	168%	172%	146%	149%	159%	180%	163%
Average	167%	192%	171%	170%	187%	204%	209%	192%	181%	187%	173%	181%	190%	200%	197%	196%	183%	170%	180%	**188%**	**185%**
Median	162%	189%	169%	172%	183%	199%	209%	202%	177%	184%	171%	170%	184%	191%	186%	208%	200%	171%	182%	**185%**	**185%**

Source: Calculations made from data contained in Value Line Investment Survey.

STANDARD & POOR'S 500 COMPOSITE RETURNS AND MARKET-TO-BOOK RATIOS 1992 - 2009

YEAR	RETURN ON AVERAGE EQUITY	MARKET-TO BOOK RATIO
1992	12.2%	271%
1993	13.2%	272%
1994	16.4%	246%
1995	16.6%	264%
1996	17.1%	299%
1997	16.3%	354%
1998	14.6%	421%
1999	17.3%	481%
2000	16.2%	453%
2001	7.5%	353%
2002	8.4%	296%
2003	14.2%	278%
2004	15.0%	291%
2005	16.1%	278%
2006	17.0%	277%
2007	12.8%	284%
2008	3.0%	224%
2009	10.6%	188%
Averages:		
1992-2001	14.7%	341%
2002-2009	12.1%	265%

Source: Standard & Poor's Analyst's Handbook, 2010 edition, page 1.

RISK INDICATORS

COMPANY	VALUE LINE SAFETY	VALUE LINE BETA	VALUE LINE FINANCIAL STRENGTH		S& P STOCK RANKING	
Proxy Group of Natural Gas Distribution Companies						
AGL Resources	2	0.75	B++	3.67	A	4.00
Atmos Energy	2	0.65	B+	3.33	A-	3.67
Laclede Group	2	0.60	B++	3.67	B+	3.33
Northwest Natural Gas	1	0.60	A	4.00	A-	3.67
Piedmont Natural Gas	2	0.65	B++	3.67	A	4.00
South Jersey Industries	2	0.65	B++	3.67	A-	3.67
Southwest Gas	3	0.75	B	3.00	B+	3.33
WGL Holdings	1	0.65	A	4.00	B+	3.33
Average	1.9	0.66	B++	3.63	A-	3.63
Hevert Proxy Group						
AGL Resources	2	0.75	B++	3.67	A	4.00
Atmos Energy	2	0.65	B+	3.33	A-	3.67
Laclede Group	2	0.60	B++	3.67	B+	3.33
New Jersey Resources	1	0.65	A	4.00	A-	3.67
Nicor	3	0.75	A	4.00	B+	3.00
Northwest Natural Gas	1	0.60	A	4.00	A-	3.67
Piedmont Natural Gas	2	0.65	B++	3.67	A	4.00
South Jersey Industries	2	0.65	B++	3.67	A-	3.67
WGL Holdings	1	0.65	A	4.00	B+	3.33
Average	1.8	0.66	B++	3.78	A-	3.59

RISK INDICATORS

GROUP	VALUE LINE SAFETY	VALUE LINE BETA	VALUE LINE FIN STR	S & P STK RANK
S & P's 500 Composite	2.7	1.05	B++	B+
Proxy Group	1.9	0.66	B++	A-
Hevert Group	1.8	0.66	B++	A-

Sources: Value Line Investment Survey, Standard & Poor's Stock Guide.

Definitions:

Safety rankings are in a range of 1 to 5, with 1 representing the highest safety or lowest risk.

Beta reflects the variability of a particular stock, relative to the market as a whole. A stock with a beta of 1.0 moves in concert with the market, a stock with a beta below 1.0 is less variable than the market, and a stock with a beta above 1.0 is more variable than the market.

Financial strengths range from C to A++, with the latter representing the highest level.

Common stock rankings range from D to A+, with the later representing the highest level.

SOUTHWEST GAS CORPORATION
RATING AGENCY RATIOS

Item	Percent	Cost	Weighted Cost	Pre-Tax Cost	
Long-Term Debt	47.70%	8.34%	3.98%	3.98%	
Common Equity	52.30%	9.75%	5.10%	8.50%	
Total	100.00%		9.08%	12.48%	1/

1/ Post-tax weighted cost divided by .60 (composite tax factor)

Pre-Tax coverage = **3.14** = (12.48% / 3.98%)

Standard & Poor's Utility Benchmark Ratios: Business Profile of "3"	A	BBB
Pre-tax coverage	2.8x - 3.4x	1.8x - 2.8x
Total debt to total capital	50%-55%	55%-65%

EXCERPT FROM ANNUAL ENERGY OUTLOOK, 2011

Table A20. Macroeconomic Indicators
(Billion 2005 Chain-Weighted Dollars, Unless Otherwise Noted)

Indicators	Reference Case 2008	2009	2015	2020	2025	2030	2035	Annual Growth 2009-2035 (percent)
Real Gross Domestic Product	13229	12881	15338	17422	20015	22735	25692	2.7%
Components of Real Gross Domestic Product								
Real Consumption	9265	9154	10444	11669	13277	15049	16978	2.4%
Real Investment	1957	1516	2590	2991	3549	4132	4853	4.6%
Real Government Spending	2503	2543	2555	2665	2796	2935	3069	0.7%
Real Exports	1648	1491	2437	3381	4488	5763	7336	6.3%
Real Imports	2152	1854	2622	3152	3845	4736	5912	4.6%
Energy Intensity (thousand Btu per 2005 dollar of GDP)								
Delivered Energy	5.49	5.33	4.90	4.42	3.94	3.66	3.25	-1.9%
Total Energy	7.57	7.36	6.65	6.02	5.38	4.88	4.45	-1.9%
Price Indices								
GDP Chain-type Price Index (2005=1.000)	1.086	1.096	1.197	1.326	1.452	1.592	1.753	1.8%
Consumer Price Index (1982-4=1.00)								
All-urban	2.15	2.15	2.39	2.69	2.98	3.30	3.66	2.1%
Energy Commodities and Services	2.36	1.93	2.44	2.86	3.26	3.66	4.10	2.9%
Wholesale Price Index (1982=1.00)								
All Commodities	1.90	1.73	2.00	2.20	2.39	2.55	2.74	1.8%
Fuel and Power	2.14	1.59	2.06	2.44	2.86	3.24	3.69	3.3%
Metals and Metal Products	2.13	1.87	2.48	2.68	2.77	2.83	2.87	1.7%
Industrial Commodities excluding Energy	1.81	1.76	2.00	2.14	2.25	2.34	2.43	1.2%
Interest Rates (percent, nominal)								
Federal Funds Rate	1.93	0.16	5.18	4.97	4.88	4.97	5.03	- -
10-Year Treasury Note	3.67	3.26	5.77	5.89	5.80	5.78	5.87	- -
AA Utility Bond Rate	6.19	5.75	7.43	7.71	7.72	7.76	7.93	- -
Value of Shipments (billion 2005 dollars)								
Service Sectors	20737	19555	23157	25591	28640	31694	34669	2.2%
Total Industrial	6720	6017	7478	7956	8397	8829	9298	1.7%
Nonmanufacturing	2039	1821	2200	2317	2388	2443	2537	1.3%
Manufacturing	4680	4197	5278	5639	6010	6386	6761	1.9%
Energy-Intensive	1635	1551	1791	1875	1938	1974	2013	1.0%
Non-energy Intensive	3046	2646	3486	3765	4071	4412	4748	2.3%
Total Shipments	27456	25573	30635	33547	37037	40523	43967	2.1%
Population and Employment (millions)								
Population, with Armed Forces Overseas	305.2	307.8	326.2	342.0	358.1	374.1	390.1	0.9%
Population, aged 16 and over	239.4	241.8	256.5	269.4	282.6	296.2	309.6	1.0%
Population, over age 65	38.9	39.7	47.1	55.1	64.2	72.3	77.7	2.6%
Employment, Nonfarm	136.7	130.9	142.3	148.7	156.1	164.2	170.7	1.0%
Employment, Manufacturing	13.4	11.9	17.4	17.1	15.8	14.3	13.1	0.4%
Key Labor Indicators								
Labor Force (millions)	154.3	154.2	160.7	166.2	170.6	175.8	182.6	0.7%
Nonfarm Labor Productivity (1992=1.00)	1.04	1.07	1.18	1.31	1.47	1.62	1.79	2.0%
Unemployment Rate (percent)	5.82	9.27	6.86	5.47	4.99	4.93	5.20	- -
Key Indicators for Energy Demand								
Real Disposable Personal Income	10043	10100	11535	13184	15114	17127	19230	2.5%
Housing Starts (millions)	0.98	0.60	1.84	1.90	1.92	1.83	1.74	4.2%
Commercial Floorspace (billion square feet)	78.8	80.2	85.5	91.5	97.4	103.5	109.8	1.2%
Unit Sales of Light-Duty Vehicles (millions)	13.19	10.40	17.02	16.80	18.23	19.64	20.63	2.7%

GDP = Gross domestic product.
Btu = British thermal unit.
- - = Not applicable.
Sources: 2008 and 2009: IHS Global Insight Industry and Employment models, September 2010. **Projections:** Energy Information Administration, AEO2011 National Energy Modeling System run REF2011.D120810C.

BEFORE THE ARIZONA CORPORATION COMMISSION

GARY PIERCE
Chairman
BOB STUMP
Commissioner
SANDRA D. KENNEDY
Commissioner
PAUL NEWMAN
Commissioner
BRENDA BURNS
Commissioner

IN THE MATTER OF THE APPLICATION OF SOUTHWEST GAS CORPORATION FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS PROPERTIES THROUGHOUT ARIZONA	)	DOCKET NO. G-01551A-10-0458

DIRECT TESTIMONY

IN SUPPORT OF

THE SETTLEMENT AGREEMENT

STEVEN M. OLEA

DIRECTOR

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JULY 29, 2011

ALL-STATE LEGAL®
EXHIBIT
S-9

TABLE OF CONTENTS

EXECUTIVE SUMMARY
SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-10-0458

Mr. Olea's testimony supports the adoption of the Settlement Agreement ("Agreement") as proposed by the Signatories in this case. This testimony describes the settlement process as open, candid and inclusive of all parties to this case. Mr. Olea explains why Staff believes this Agreement is in the public interest. In addition, Mr. Olea summarizes the different portions of the Agreement and explains the two decoupling Alternatives put forth in the Agreement.

Mr. Olea's testimony recommends that the Commission adopt the Agreement as proposed, with the selection of either decoupling Alternative A or B.

SECTION I - INTRODUCTION

Q. Please state your name and business address.

A. Steven M. Olea, 1200 West Washington, Phoenix, Arizona, 85007.

Q. By whom and in what capacity are you employed?

A. I am employed by the Arizona Corporation Commission ("Commission") as the Director of the Utilities Division ("Division").

Q. Please state your educational background.

A. I graduated from Arizona State University ("ASU") in 1976 with a Bachelors Degree in Civil Engineering. From 1976 to 1978 I obtained 47 graduate hours of credit in Environmental Engineering at ASU.

Q. Please state your pertinent work experience.

A. From April 1978 to October 1978 I worked for the Engineering Services Section of the Bureau of Air Quality Control in the Arizona Department of Health Services ("ADHS"). My responsibilities were to inspect air pollution sources to determine compliance with ADHS rules and regulations.

From November 1978 to July 1982 I was with the Technical Review Unit of the Bureau of Water Quality Control ("BWQC") in ADHS (this is now part of the Arizona Department of Environmental Quality ["ADEQ"]). My responsibilities were to review water and wastewater construction plans for compliance with ADHS rules, regulations, and Engineering Bulletins.

From July 1982 to August 1983 I was with the Central Regional Office, BWQC, ADHS. My responsibilities were to conduct construction inspections of water and wastewater facilities to determine compliance with plans approved by the Technical Review Unit. I also performed routine operation and maintenance inspections to determine compliance with ADHS rules and regulations, and compliance with United States Environmental Protection Agency requirements.

From August 1983 to August 1986 I was a Utilities Consultant/Water-Wastewater Engineer with the Division. My responsibilities were to provide engineering analyses of Commission regulated water and wastewater utilities for rate cases, financing cases, and consumer complaint cases. I also provided testimony at hearings for those cases.

From August 1986 to August 1990 I was the Engineering Supervisor for the Division. My primary responsibility was to oversee the activities of the Engineering Section, which included one technician and eight Utilities Consultants. The Utilities Consultants included one Telecommunications Engineer, three Electrical Engineers, and four Water-Wastewater Engineers. I also assisted the Chief Engineer and performed some of the same tasks as I did as a Utilities Consultant.

In August 1990 I was promoted to the position of Chief Engineer. My duties were somewhat the same as when I was the Engineering Supervisor, except that now I was less involved with the day-to-day supervision of the Engineering Staff and more involved with the administrative and policy aspects of the Engineering Section.

In April 2000 I was promoted to the position of one of two Assistant Directors of the Division. In this position I assisted the Division Director in the policy aspects of the Division. I was primarily responsible for matters dealing with water and energy.

In August 2009 I was promoted to my present position as Director of the Utilities Division. In this position I manage the day-to-day operations of the Utilities Division with the assistance of the Utilities Division Assistant Director and oversee the management of the Division's Telecom & Energy Section, the Financial & Regulatory Analysis Section, the Consumer Services Section, the Engineering Section and the Administrative Section. In addition, I am responsible for making policy decisions for the Division.

In early 2010 I was given the task of being the Interim Director for the Commission's Safety Division (Railroad and Pipeline). The day-to-day activities of the Safety Division are overseen by the managers of the Railroad Safety Section and the Pipeline Safety Section with input from me. Together with the Commission's Executive Director, I am responsible for the policy decisions for the Safety Division.

Q. What is the purpose of your testimony in this case?

A. The purpose of my testimony is to support the Proposed Settlement Agreement ("Agreement"). I will also provide testimony which addresses the settlement process, public interest benefits and general policy considerations.

Q. Did you participate in the negotiations that led to the execution of the Agreement?

A. Yes, I did.

Q. How is your testimony being presented?

A. My testimony is organized into five sections. Section I is this introduction, Section II provides discussion of the settlement process, Section III discusses the various parts of the Agreement, Section IV identifies and discusses the reasons why the Agreement is in the public interest and Section V addresses general policy considerations.

Q. Will there be other Staff witnesses providing testimony in this case?

A. Yes. Mr. Ralph Smith will be providing testimony to explain the earnings test for decoupling Alternative B, and Ms. Barbara Keene will be providing testimony with regard the energy efficiency process resulting from the Agreement. In addition, all Staff witnesses that filed Direct Testimony prior to the Agreement will be available if the Commission has questions for them.

SECTION II – SETTLEMENT PROCESS

Q. Please discuss the settlement process.

A. The settlement process was open, transparent and inclusive. All parties received notice of the settlement meetings and were accorded an opportunity to raise, discuss, and propose resolution to any issue that they desired.

Q. How many settlement meetings were held?

A. There were approximately six large group settlement meetings relating to revenue requirement, decoupling, energy efficiency programs and rate design. In addition, there were numerous other discussions involving individual parties.

Q. Who participated in those meetings?

A. The following parties were participants in some or all of the meetings: Southwest Gas Corporation ("Southwest" or "Company"); the Residential Utility Consumer Office ("RUCO"); the Arizona Investment Council ("AIC"); the Southwest Energy Efficiency Project ("SWEEP"), Cynthia Zwick, Tucson Electric Power Company ("TEP"), Natural Resources Defense Council ("NRDC") and Division Staff ("Staff").

Q. Could you identify some of the diverse interests that were involved in this process?

A. Yes. The diverse interests included Staff, RUCO, Southwest, a shareholders association, consumer representatives, demand-side management ("DSM") advocates, low-income costumer advocates, and renewable energy advocates.

Q. How many of these parties executed the Agreement?

A. The Agreement was signed by Southwest, Staff, Ms. Zwick, SWEEP, NRDC and AIC ("Signatories").

Q. Were there parties who chose not to execute the Agreement?

A. Yes, RUCO and TEP.

Q. Why did RUCO and TEP not sign on to the Agreement?

A. I do not know and would not want to speculate.

Q. Was there an opportunity for all issues to be discussed and considered?

A. Yes, each party had the opportunity to raise and have its issues considered.

Q. Were the Signatories able to resolve all issues?

A. Yes, the Signatories were able to resolve and reach agreement on all issues.

Q. How would you describe the negotiations?

A. I believe that all participants zealously advocated and represented their interests. I would characterize the discussions as candid but professional. While acknowledging that not all parties executed the Agreement, I must re-emphasize that all parties had the opportunity to be heard and to have their issues fairly considered.

Q. Would you describe the process as requiring give and take?

A. Yes, I would. As a result of the varied interests represented in the settlement process, a willingness to compromise was necessary. As evidenced in the Agreement, the Signatories compromised on what could be described as vastly different litigation positions.

Q. Because of such compromising, do you believe the public interest was compromised?

A. No. As I will discuss later in this testimony, I believe that the compromises made by the various parties further the public interest.

Q. Mr. Olea, you have indicated that the Agreement incorporates diverse interests including those of low-income customers, residential customers, energy efficiency advocates and the investment community. Please discuss how the Agreement addresses the diverse interests of these entities.

A. In the Agreement, there are specific provisions which address many of the concerns expressed by the various interests. For example, the low-income customer issues are addressed in Section IV. Another example is Section V.C., which addresses the interests of those concerned about promoting energy efficiency. The Revenue Decoupling piece (Part III) addresses the concerns of those interested in not only energy efficiency, but also those concerned with the financial integrity of the Company and protection of the rate payers.

SECTION III – SETTLEMENT AGREEMENT

Q. Please describe Part I of the Agreement.

A. Part I is a general description of the settlement process and the Agreement itself.

Q. Please describe Part II of the Agreement.

A. Part II is a summary of the Direct Testimony revenue requirement recommendations of the Company, Staff and RUCO. The Company's and Staff's recommendations are discussed later in this testimony. Depending on which decoupling Alternative is considered, the revenue requirement in the Agreement is equal to or less than that recommended by Staff in its Direct Testimony.

Q. Please describe Part III of the Agreement.

A. Part III describes, in detail, the decoupling Alternative A and decoupling Alternative B. These Alternatives are discussed later in this testimony.

Q. Please discuss Part IV of the Agreement.

A. Part IV details the benefits to customers on the Company's low-income tariffs. The Company commits to working with the parties to enhance its education and outreach for its Low Income Energy Conservation weatherization program and to provide $1 million of non-rate payer funds over the next five years for this program. Any increase to the DSM adjustor shall not be passed on to customers on the low-income tariffs. The proposed

Customer Owned Yard Line ("COYL") adjustor shall not be passed on to customers on the low-income tariffs. The average bill increase for customers on the low-income tariffs will be less than the general rate increase and the current 20 percent discount for the first 150 therms in each winter month will be increased to 30 percent.

Q. Please describe Part V of the Agreement.

A. Part V discusses other items that were agreed to by the Signatories, such as Cost of Capital, Rate Base, Energy Efficiency, COYL Replacement Program, an Expense Reduction Plan, costs incurred by Southwest for Development of Gas Heat Pump Technology, and various other items.

Q. Would you like to elaborate on how the Agreement addresses some of the specific items covered in Part V?

A. Yes. I would like to specifically describe the COYL program because it is not discussed anywhere else in this testimony and the Agreement proposes the establishment of an adjustor mechanism for the replacement of COYLs. I would also like to highlight how the Agreement provides for an Expense Reduction Plan, and addresses costs incurred by Southwest for the Development of Gas Heat Pump Technology,

Q. What is a COYL?

A. A COYL results from residential service that is not provided by the "normal" meter and service line configuration. The normal configuration is one where the meter serving the residence is located immediately adjacent to the housing structure and the service line from the gas main to the meter is owned by Southwest. In the Tucson area of Southwest's service territory there are over 100,000 services that are provided where the meter is at or near the property line of the residence and the service line from the meter to the residence is owned by the customer or property owner (very similar to a water system), hence the term Customer Owned Yard Line.

In cases where these COYLs develop leaks, the responsibility for repairing these leaks falls on the customer. When Southwest becomes aware of such a leak, the Company notifies the customer that the leak must be repaired and turns off service to that customer until the leaking line is repaired or replaced. Many of these COYLs are on older homes where the customer may have difficulty (financially) in replacing or repairing the COYL.

Q. **Please discuss the Company's proposed pilot program for COYLs.**

A. In its application, Southwest had proposed a pilot program to spend $10,000,000 to replace a portion of these lines. The total cost to replace all these lines could exceed $200,000,000. Staff's recommendation was to deny the Company's pilot program request, and instead have Southwest perform a leak survey to determine the extent of the COYL leak problem and then come up with a replacement program.

Q. **What is the resolution of the COYLs?**

A. The Agreement at Section V-D, paragraphs 5.13 through 5.19, calls for Southwest to purchase Remote Methane Leak Detection ("RMLD") devices to conduct leak surveys of these COYLs. As a leak is discovered (either through the Company's leak survey program or through a customer call to Southwest), Southwest will replace these COYLs with a normal service configuration. Southwest will account for these replacements on an annual basis and submit this accounting to the Commission on an annual basis. Based on the amount of plant installed each year, Southwest will be allowed to add a surcharge to its bills that would basically be equal to the amount that would have been assessed had this additional plant been in rate base during the test year. Using this method will allow

Southwest to maintain a system free of COYL leaks without requiring customers that may not be able to fix such leaks from having their gas service terminated.

Q. Please describe the expense reduction plan that is provided for in the Agreement.

A. Part V-E, paragraph 5.20 provides for an expense reduction plan that requires Southwest to reduce its expenses on an annual basis by an average of $2.5 million per year beginning in 2012. Southwest Gas agrees the $2.5 million average annual expense reduction commitment will continue through the end of the test year in the Company's next general rate case. The $2.5 million annual expense reduction by Southwest Gas represents an average annual reduction - in some years, it may exceed $2.5 million.

Q. Please describe how the issues relating to costs incurred by Southwest relating to developing Gas Heat Pumps are addressed in the Agreement.

A. The Agreement addresses the issues raised in Staff's direct testimony concerning the costs incurred by Southwest related to developing Gas Heat Pump Technology in Part V-K, paragraphs 5.29 through 5.32. In summary:

- All gas heat pump technology development costs shall be removed from operating expenses.

- No new gas heat pump projects shall be funded through the research and development surcharge.

- Southwest will prepare an accounting for all gas heat pump technology development costs that have been funded by Arizona ratepayers through base rates and the research and development surcharge through the date of the Commission's final order in this case. Southwest will track the Arizona ratepayer funding for gas heat pump technology development as a potential regulatory liability, to be returned to ratepayers, only to the extent commercial development occurs and revenues and royalties are received by Southwest and profits and royalties are received by any other entities that are affiliated with Southwest including but not limited to IntelliChoice Energy LLC.

- Southwest will prepare a plan to reimburse Arizona ratepayers for their proportionate level of funding of gas heat pump technology development costs. This plan will include a methodology for how the benefits of any commercialization revenues and royalties associated with the gas engine driven air conditioning units are to be shared with Southwest's Arizona ratepayers to ensure that customers receive credit for any investment that contributed to the development of this technology. Southwest will file its above-referenced plan and related information with the Commission, with service to the Parties to this Docket within 90 days of the effective date of an order approving this Agreement. Within 120 days of Southwest's submittal of this plan and related information, Staff will submit its recommendation to the Commission for its consideration.

Q. Please describe Part VI of the Agreement.

A. This is the Force Majeure provision which allows Southwest, in an emergency situation, to request from the Commission relief from the rate increase application moratorium, if the Commission chooses Alternative B.

Q. Please describe Part VII of the Agreement.

A. Part VII sets forth the Signatories understanding of the Commission's independent authority in the review and consideration of the Agreement. This section also describes the rights of the Signatories should the Commission fail to adopt the material terms of the Agreement. In this section, the Signatories agree to waive the right to challenge a Commission decision solely on the basis of the Commission selection of either Alternative A or B.

Q. Please describe Part VIII of the Agreement.

A. Part VIII is the legal "fine print" that describes the settlement process as a give and take; sets forth the role of the Signatories to support the Agreement. It also describes the Signatories legal rights with respect to the Agreement and future proceedings.

SECTION IV - PUBLIC INTEREST

Q. Mr. Olea, is the Agreement in the public interest?

A. Yes, in Staff's opinion, the Agreement is fair, balanced, and in the public interest.

Q. Would you summarize the reasons that lead Staff to conclude that the Agreement is fair, balanced, and in the public interest?

A. This Agreement results in a settlement package that addresses Southwest's need for a rate increase while balancing this need with terms and conditions that provide customer benefits, such as:

- Commitments Benefiting Low Income Customers on the low income rate schedule(s).
    - An increased Low Income Rate Assistance discount from 20 percent to

30 percent for the low income rate schedule(s) for the first 150 therms in each winter month.

- A Company commitment to increase funding for Low Income Energy Conservation Weatherization program with non-ratepayer funds of at least $1 million over 5 years.
- A Company commitment to develop enhanced communication programs to increase awareness of low-income programs.

- Rate Stability.
  - Alternative decoupling mechanisms each of which will improve Southwest's revenue stability, which, in turn, has a positive impact on its financial profile and credit ratings - benefiting customers through keeping future debt costs as low as possible.
  - Alternative decoupling mechanisms, with rate payer protections, each of which will mitigate future rate increases and reduce the frequency of time consuming and expensive rate cases.
  - A moratorium on general rate case applications for over five years if the Commission chooses decoupling Alternative B.

- A Company commitment to reduce expenses by at least $2.5 million per year.

- Continuation of a 20-Year Plan to replace Early Vintage Plastic Pipe.

- The Establishment of a COYL Replacement Program.

- Provisions to address costs incurred by Southwest for development of Gas Heat

Pump technology, including an accounting by Southwest of all such costs charged to Arizona ratepayers, and development by Southwest of a plan to reimburse Arizona ratepayers for their proportionate level of funding of gas heat pump technology development costs.

- Energy efficiency initiatives resulting in customer annual energy savings of at least 1,250,000 therms within nine months of the Commission's approval of the modified EE and RET plan.

- Implementation of a decoupling mechanism - either Alternative A or B.
  - Aligns utility, customer and societal interests to pursue annual customer bill savings through the recently enacted gas energy efficiency rules.
  - Providing the Company with incentives to support customer energy efficiency.
  - Providing protection for customers from high winter monthly bills following extreme weather events.

- Rate Design.
  - No increase to the monthly basic service charge to enhance customer bill savings through energy efficiency and conservation efforts.

Q. Mr. Olea, do you believe that the Agreement results in just and reasonable rates for consumers?

A. Yes. In its Rate application, Southwest proposed a revenue increase in the amount of $73.2 million. Staff recommended a revenue increase of $54.9 million. In the Agreement, based on the decoupling alternative ultimately adopted by the Commission (Alternative A or B), the Signatories recommended a revenue increase of $54.9 million for Alternative A and $52.6 million for Alternative B, which represent an increase that is considerably less than the $73.2 million the Company requested in its application. In other words, if the Agreement is adopted by the Commission, the revenue increase will be no higher than that recommended by Staff in its Direct Testimony. In addition, the approval of a decoupling mechanism will mitigate rate increases in future rate proceedings and reduce the frequency of time consuming and expensive rate cases.

Q. Please discuss how the Agreement is fair to the utility.

A. The revenue recommended will provide Southwest with adequate funds to provide reliable and safe service, while at the same time ensuring the financial health of the Company. The approval of a decoupling mechanism will also improve Southwest's revenue stability, which will have a positive impact on its financial profile and credit ratings.

Q. Mr. Olea, what was Staff's goal when it agreed to be a signatory to the Agreement?

A. The primary goal of Staff in this matter, as in all rate proceedings before the Commission, is to protect the public interest by recommending rates that are just, fair and reasonable for both the rate payers and the Company. Staff believes it has accomplished this by reviewing the facts presented and making the appropriate recommendations to the Commission for its consideration, which will balance the interest of the Company and the ratepayers, by promoting the Commission's desire to ensure that the Company has the tools and financial health to provide safe, adequate and reliable service and fulfill the Commission's energy efficiency goals.

SECTION V – POLICY CONSIDERATIONS

Q. Mr. Olea, would you say that there was one major policy consideration the parties had to deal with in this Docket?

A. Yes, the major policy consideration that Staff and other signatories dealt with in order to balance the interest of all parties was revenue decoupling. The Commission, in Docket Nos. E-00000J-08-0314 and G-00000C-08-0314, issued its Policy Statement Regarding Utility Disincentives to Energy Efficiency and Decoupled Rate Structures ("Policy Statement"). The Policy Statement did not adopt a requirement or mandate for a specific revenue decoupling mechanism, but noted that utilities may file a proposal for decoupling or an alternative mechanism for addressing disincentives, in their next general rate case. Southwest was the first utility after the issuance of the Policy Statement that proposed a revenue decoupling mechanism as part of its rate application.

Q. Please describe the Company's decoupling proposal.

A. Southwest proposes to implement revenue decoupling on a revenue per customer ("RPC") basis. An RPC-based mechanism is a form of revenue decoupling that starts with the determination of an allowed RPC, typically derived from the outcome of a concurrent rate proceeding. The allowed (test year) revenue requirement, divided by the total number of test year customers is then utilized as the allowed RPC for future revenue decoupling reconciliation purposes. Future decoupling reconciliations compare actual RPC (actual revenues collected from the actual number of customers in the reconciliation period) to allowed RPC to determine a per-customer revenue deficiency or surplus. This per customer difference is then multiplied by the number of actual customers in the reconciliation period to arrive at a total revenue deficiency or surplus. This deficiency or surplus is divided by reconciliation period sales to develop a per therm surcharge or credit that will be applied to the upcoming twelve-month recovery period. The second component of the Company's revenue decoupling mechanism includes a true-up for weather-related differences in usage during its heating season months. Ratepayers would be issued a credit (or assessed a charge) if the prior month's weather was colder (or warmer) than normal.

Q. What was Staff's recommendation on this issue in its Direct Testimony?

A. Staff recommended that the Commission deny the Company's request. Staff proposed an alternative decoupling mechanism that would tie the Company's performance in its energy efficiency efforts to potential lost base revenue recovery. Staff believes that if the Commission is going to require Southwest to achieve specific energy efficiency goals, i.e., sell less natural gas per customer than it did in the test year, then the Commission should not expect Southwest to do this without accounting for these lower sales. Therefore, Staff's proposal assumes the Company will begin meeting these goals once the rates from this case go into effect and as such the rates have been designed based on these lower gas sales. The Company would not be allowed to begin recovering the second step of energy efficiency until it meets the first step goal.

Q. Please briefly explain what is stipulated in the Agreement on the issue of decoupling.

A. Because of the unique circumstances of decoupling, the Signatories agreed to present the Commission with two alternative decoupling proposals. Alternative A, is a partial revenue decoupling mechanism consisting of two components: a Lost Fixed Cost Recovery ("LFCR") component and a weather component. It is basically a melding of Staff's original proposal and Staff's understanding of the alternative weather decoupling concept put forth by RUCO in its direct testimony. Alternative A would permit Southwest to recover lost base revenues attributable to achievement of the Commission's required annual energy savings (as described in my preceding answer) and to adjust customer bills each month when actual weather during the billing cycle differs from the average weather used in the calculation of rates. The Agreement also requires the Company to make a refund to customers for those years where it did not meet the energy efficiency targets. Any party can also petition to have this decoupling mechanism modified or eliminated if Southwest misses the energy efficiency targets two years in a row.

Alternative B is a full revenue decoupling mechanism whereby rates will adjust to reflect any differences between authorized revenues per customer and actual revenues per customer, as proposed by the Company in its Application. This full revenue decoupling mechanism also includes a monthly weather component. Alternative B calls for an annual review with an earnings test to ensure that the Company does not earn more than its authorized rate of return resulting from this Docket. This Alternative also contains a rate filing moratorium whereby the Company cannot file for an increase in rates that would take effect prior to May 1, 2017.

Q. What is the revenue increase and cost of equity under Alternative A?

A. Alternative A proposes an overall revenue increase of $54,927,101, a return on common equity of 9.75 percent, and a fair value rate of return ("FVROR") of 7.02 percent on the fair value rate base ("FVRB") of $1,452,932,391. This is the same as Staff's original recommendation contained in its Direct Testimony.

Q. What is the revenue increase and cost of equity under Alternative B?

A. Alternative B proposes an overall revenue increase of $52,607,414, a return on common equity of 9.50 percent, and a FVROR of 6.92 percent on FVRB of $1,452,932,391. As can be seen, these values are all less than Staff's original recommendation.

Q. Mr. Olea, please explain Staff's rationale for being a signatory to the Agreement which contains a different recommendation with regard to decoupling than the recommendation offered by Staff in its Direct Testimony.

A. As noted above, the Agreement contains two options for the Commission consideration – with Alternative A basically being Staff's and RUCO's positions combined and Alternative B being the Company's full revenue decoupling proposal.

Let me speak to Alternative A first. Alternative A is basically the adoption of all Staff's recommendations, not just revenue decoupling, with the addition of a weather component that would offer some protection from high bills during extreme cold-weather events. Therefore, it was rather easy for Staff to agree to Alternative A.

Alternative B is somewhat of a deviation from Staff's Direct Testimony. I say 'somewhat', because in its Direct Testimony, Staff stated that it could not support the full revenue decoupling mechanism as proposed by the Company, without some rate payer protections and benefits. Staff believes that the Alternative B as proposed in the Agreement contains the ratepayer protections and benefits that were implicitly required by Staff in its Direct Testimony. Those protections/benefits include:

- The Company may not file a new rate increase application with rates that take effect prior to May 1, 2017.

- The Return on Equity is 25 basis points less (9.5% instead of 9.75%) than recommended by Staff in its Direct Testimony, resulting in a revenue increase that is $2,319,687 less than Staff's original recommendation.

- The cap on the decoupling mechanism surcharge is five percent (5%) of the non-gas base revenues, which is actually less than five percent of the total bill, since a customer's bill consists of both gas and non-gas components.

- There is no cap on any surcredit (refund) to customers resulting from the decoupling mechanism.

- Southwest is required to file quarterly reports and an annual report that will be reviewed at an Open Meeting by the Commissioners each year. At this Open Meeting, if the Commissioners determine that the decoupling mechanism is not working as intended, the Commission can begin a proceeding to modify or eliminate the decoupling mechanism.

- As a result of this decoupling mechanism, Southwest will be subject to an annual earnings test to ensure that it does not earn more than its authorized rate of return and that a decoupling surcharge will not be implemented, regardless of how successful Southwest is in achieving the energy efficiency targets, if the earnings test indicates that Southwest is earning its authorized rate of return.

- A customer outreach and education program regarding decoupling.

Q. Is there anything else you would like to add regarding the Agreement?

A. Yes. First, I would like to point out that with most settlement agreements I have seen come before the Commission, the agreements have recommended a revenue increase that is somewhere between Staff's original proposal and the utility's. In this case, the Agreement has a revenue increase that is equal to or less than that originally proposed by Staff.

Second, based on all the above, Staff believes that the Agreement as proposed is fair, balanced, and in the public interest. Therefore, Staff recommends that the Agreement be approved by the Commission as proposed with the adoption of either decoupling mechanism Alternative A or B.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE ARIZONA CORPORATION COMMISSION

GARY PIERCE
Chairman
BOB STUMP
Commissioner
SANDRA D. KENNEDY
Commissioner
PAUL NEWMAN
Commissioner
BRENDA BURNS
Commissioner

IN THE MATTER OF THE APPLICATION OF SOUTHWEST GAS CORPORATION FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS PROPERTIES THROUGHOUT ARIZONA	DOCKET NO. G-01551A-10-0458

DIRECT TESTIMONY

IN SUPPORT OF

THE SETTLEMENT AGREEMENT

RALPH C. SMITH

ON BEHALF OF THE

UTILITIES DIVISION STAFF

ARIZONA CORPORATION COMMISSION

JULY 29, 2011

ALL-STATE LEGAL® EXHIBIT S-11

TABLE OF CONTENTS

EXECUTIVE SUMMARY
SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-10-0458

My testimony in support of the settlement addresses the earnings test that would be applied under Alternative B for decoupling.

SECTION I – INTRODUCTION

Q. Please state your name and business address.

A. Ralph C. Smith, Larkin & Associates PLLC, 15728 Farmington Road, Livonia, MI 48154.

Q. Are you the same Ralph C. Smith who has filed Direct Testimony in this proceeding?

A. Yes.

Q. What is the purpose of your testimony in this case in support of the Settlement Agreement?

A. The purpose of my testimony is to support the Proposed Settlement Agreement ("Agreement") by discussing the earnings test that would apply under the Alternative B decoupling scenario.

Q. Did you participate in discussions that led to the execution of the Agreement?

A. Yes, I did.

Q. How is your testimony being presented?

A. My testimony is organized into two sections. Section I is this introduction. Section II provides a discussion of the earnings test for decoupling Alternative B.

SECTION II – EARNINGS TEST UNDER DECOUPLING ALTERNATIVE B

Q. What is an earnings test?

A. An earnings test is a review of a utility's accounting information, typically with required ratemaking adjustments, to examine or "test" how the utility's earnings compare with its authorized rate of return.

Q. Please discuss the earnings test that would apply under Decoupling Alternative B.

A. As described by Staff witness Olea, the Agreement provides for an Alternative B decoupling proposal, which includes an annual earnings test. Southwest Gas Corporation ("Southwest") will be subject to an annual earnings test to ensure that it does not earn more than its authorized rate of return, and a decoupling surcharge will not be implemented, regardless of how successful Southwest is in achieving the energy efficiency targets, if the earnings test indicates that Southwest is earning its authorized rate of return. Southwest shall include in its annual report, commencing April 30, 2013, the results of its annual earnings test in a format consistent with the report attached as Exhibit A to the Agreement.

Q. How would the earnings test operate?

A. The fair value rate base ("FVRB") and fair value rate of return ("FVROR") would be held at the same levels as Staff's filed Direct Testimony. Southwest's earnings would be tested by reviewing recorded operating income statement information, adjusted for ratemaking adjustments.

Q. Please describe the specific data points and ratemaking adjustments that will be made.

A. The data points and assumptions to be utilized in the earnings test report will include the following:

- The annual reporting period shall consist of the twelve months ended December 31;
- Fair value rate base shall be held constant at $1,452,933,391;

- Fair value rate of return shall be held constant at 6.92 percent, and all related cost of capital components held constant, including capital structure (52.30 percent equity and 47.70 percent debt), cost of debt (8.34 percent), cost of equity (9.50 percent), and return on fair value increment (1.25 percent).

The earnings test will use:

- Experienced non-gas revenue for the reporting period; and
- Recorded operating expenses for the reporting period, adjusted for certain ratemaking adjustments.

The ratemaking adjustments will consist of recorded dollars less the Staff-specified disallowance percentage for the following Staff adjustments:

- C-3, Management Incentive Program ("MIP") expense will be limited to fifty percent of the recorded and allocated cost; however, Staff may make a further adjustment if Staff believes the MIP expense has increased unreasonably;
- C-4, the cost of all stock-based compensation (other than MIP) shall be excluded;
- C-5, all Supplemental Executive Retirement Expense charged or allocated to Arizona operation shall be excluded;
- C-6, forty percent of American Gas Association dues shall be excluded;
- C-7, all losses related to the sale of employee homes for relocation shall be excluded;
- C-9, all Gas Heat Pump Research and Development Expenses shall be excluded;
- C-11, fifty percent (50%) of all Directors' and Officers' Liability Insurance expense shall be excluded; and

- C-13, leased aircraft expense shall be limited to the lesser of (1) the actual recorded amount or (2) an allowance of $472,000.

Q. How will the other issues addressed in Staff's adjustments be handled in the earnings test calculations?

A. Staff's Schedule B adjustments and Staff's Schedule C adjustments C-1 (Completed Construction Not Classified Correction), C-2 (Yuma Manors Pipe Replacement), and C-10 (Interest Synchronization) will remain constant because rate base and FVROR remain constant for the purposes of the earnings test.

Staff's Schedule C adjustment C-8 (Rent Charged to Affiliate IntelliChoice Energy LLC) and C-14 (COYL Leak Detection Survey) will be recorded in Southwest Gas' operating expenses going forward, so no further adjustment will be necessary for the earnings test.

Staff's Adjustment C-12, Reserve for Self Insurance, is a normalizing adjustment and Southwest Gas will use its recorded amounts for purposes of the earnings test.

For purposes of calculating income taxes, interest expense will be held constant since the FVRB and FVROR will be held constant.

Finally, any surcharge revenues and expenses will not be included in the earnings test.

Q. Does this conclude your testimony in support of the settlement?

A. Yes.

BEFORE THE ARIZONA CORPORATION COMMISSION

GARY PIERCE
Chairman
BOB STUMP
Commissioner
SANDRA D. KENNEDY
Commissioner
PAUL NEWMAN
Commissioner
BRENDA BURNS
Commissioner

IN THE MATTER OF THE APPLICATION OF SOUTHWEST GAS CORPORATION FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS PROPERTIES THROUGHOUT ARIZONA.	DOCKET NO. G-01551A-10-0458

DIRECT TESTIMONY

SUPPORTING THE SETTLEMENT AGREEMENT

OF

BARBARA KEENE

PUBLIC UTILITIES ANALYST MANAGER

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JULY 29, 2011

ALL-STATE LEGAL®
EXHIBIT
S-12

TABLE OF CONTENTS

APPENDICES

EXECUTIVE SUMMARY
SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-10-0458

This testimony addresses the provisions of the Settlement Agreement regarding Energy Efficiency and Renewable Energy Resource Technology.

INTRODUCTION

Q. Please state your name and business address.

A. My name is Barbara Keene. My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. By whom are you employed and in what capacity?

A. I am employed by the Utilities Division ("Staff") of the Arizona Corporation Commission as a Public Utilities Analyst Manager. My duties include supervising the energy portion of the Telecommunications and Energy Section. A copy of my résumé is provided in Appendix 1.

Q. As part of your employment responsibilities, were you assigned to review matters contained in Docket No. E-01345A-10-0458?

A. Yes.

Q. What is the subject matter of this testimony?

A. This testimony will provide support for the Settlement Agreement ("Agreement") filed on July 15, 2011, by addressing Section V.C. of the Agreement regarding Energy Efficiency and Renewable Energy Resource Technology.

ENERGY EFFICIENCY AND RENEWABLE ENERGY RESOURCE TECHNOLOGY

Q. What does the Agreement address regarding Energy Efficiency and Renewable Energy Resource Technology?

A. Section V.C. of the Agreement describes how Southwest Gas Corporation ("Southwest") intends to meet the Commission's energy efficiency goals, as established in the Gas Utility Energy Efficiency Standards (A.A.C. R14-2-2501 through 2520 *et seq.*).

Q. Please describe the energy efficiency goals contained in R14-2-2504.

A. R14-2-2504 requires Southwest to achieve cumulative annual energy savings, expressed as therms or therm equivalents, equal to at least six (6) percent of Southwest's retail gas energy sales for calendar year 2019. The goals are shown in Table 1.

Table 1
Energy Efficiency Standard

Year	Cumulative Annual Energy Savings as % of Retail Energy Sales in Prior Calendar Year
2011	0.50%
2012	1.20%
2013	1.80%
2014	2.40%
2015	3.00%
2016	3.60%
2017	4.20%
2018	4.80%
2019	5.40%
2020	6.00%

Q. How can Southwest meet these energy savings requirements?

A. At least 75 percent of the therms or therm equivalents must be saved through energy efficiency ("EE") programs. The remaining therms or therm equivalents may be saved through combined heat and power ("CHP") programs, renewable energy resource technology ("RET") programs, and through building codes and appliances standards.

Q. What is EE?

A. EE is the production or delivery of an equivalent level and quality of end-use gas service using less energy, or the conservation of energy by end-use customers.

Q. What is CHP?

A. CHP uses a primary energy source to simultaneously produce electrical energy and useful process heat. CHP would be used to displace space heating, water heating, or another load.

Q. What is RET?

A. A RET is an application utilizing an energy resource that is replaced rapidly by a natural, ongoing process and that displaces conventional energy resources otherwise used to provide energy.

Q. Was Southwest required to file an implementation plan, describing how Southwest plans to meet the EE standards?

A. Yes. R14-2-2505 requires an Implementation Plan to be filed at least in every odd year.

Q. Did Southwest file an Implementation Plan pursuant to R14-2-2505?

A. Yes. Southwest included an Arizona Energy Efficiency and Renewable Energy Resource Technology Portfolio Implementation Plan ("EE & RET Plan") as part of its rate case application.

Q. Did Staff have concerns with the EE and RET Plan that Southwest filed with the rate case application?

A. Yes. As discussed in the Direct Testimony of Staff witness Julie McNeely-Kirwan, Southwest had performed its cost-effectiveness analyses at the program level rather than the measure level. However, Staff believes the cost-effectiveness analyses should be performed at the measure level, which would be consistent with the methodology used by

Staff in previous recommendations and is consistent with the intent of the Gas Energy Efficiency Rules.

Q. Does the Agreement provide for modifications to Southwest's EE and RET Plan?

A. Yes. Under the Agreement, Southwest agrees to modify the EE and RET Plan by providing supplemental information to Staff for EE measures that are cost-effective at the measure level. With the addition of cost-effective measures, Southwest expects to save at least 1,250,000 therms from existing and new Commission-approved measures within nine months of Commission approval of the modified EE and RET Plan.

Q. Has Southwest provided the supplemental information to Staff?

A. Yes.

Q. How will the supplemental information be processed?

A. Staff is currently reviewing the supplemental information provided by Southwest Gas. This information will be utilized in conducting Staff's cost-benefit analyses of various energy efficiency measures. Once this review is completed, Staff will file a memo and proposed order prior to the Open Meeting where the Commission intends to vote on the Recommended Opinion and Order regarding the Agreement. Staff will strive to include recommendations regarding as many measures as possible in its memo and proposed order. The Settlement states that the Signatories urge the Commission to vote on Staff's proposed Order on the same date that the Commission votes on the Agreement.

Q. **With the EE and RET Plan modified by the supplemental information discussed above, do the Signatories to the Agreement believe that Southwest will be able to meet the 2011 energy savings goal required by R14-2-2504?**

A. Southwest may not be able to meet the 2011 energy savings goal with only the EE and RET Plan modified with the supplemental information discussed above.

Q. **Does the Agreement provide Southwest with a means to increase the opportunity for energy savings so that it is more likely to meet the energy savings goals for 2011 and beyond?**

A. Yes. Within 60 days of filing the Agreement Southwest will file, in a new docket, a new and revised EE and RET Implementation Plan. This new EE and RET Implementation Plan will be incremental to the EE and RET Plan modified with the supplemental information discussed above. Southwest intends to meet the 2011 energy savings goal within 12 months of Commission approval of the new EE and RET Implementation Plan. For all subsequent years, Southwest will file its implementation plans consistent with R14-2-2505. This rule requires the plans to be filed on June 1 of each odd year or annually at the election of each utility. Southwest has committed to work with Staff and Southwest Energy Efficiency Project ("SWEEP") to avoid the need to file a request for a waiver during any plan year from 2011-2015 in lieu of submitting a plan designed to achieve the energy savings goals.

Q. **Does this conclude your Direct Testimony?**

A. Yes, it does.

RESUME

BARBARA KEENE

Education

B.S.	Political Science, Arizona State University (1976)
M.P.A.	Public Administration, Arizona State University (1982)
A.A.	Economics, Glendale Community College (1993)

Additional Training

Management Development Program - State of Arizona, 1986-1987
UPLAN Training - LCG Consulting, 1989, 1990, 1991
Various seminars, workshops, and conferences on ratemaking, energy efficiency, rate design, computer skills, labor market information, training trainers, and Census products

Employment History

Arizona Corporation Commission, Utilities Division, Phoenix, Arizona: Public Utilities Analyst Manager (May 2005-present). Supervise the energy portion of the Telecommunications and Energy Section. Conduct economic and policy analyses of public utilities. Coordinate working groups of stakeholders on various issues. Prepare Staff recommendations and present testimony on electric resource planning, rate design, special contracts, energy efficiency programs, and other matters.

Arizona Corporation Commission, Utilities Division, Phoenix, Arizona: Public Utilities Analyst V (October 2001-May 2005), Senior Economist (July 1990-October 2001), Economist II (December 1989-July 1990), Economist I (August 1989-December 1989). Conduct economic and policy analyses of public utilities. Coordinate working groups of stakeholders on various issues. Prepare Staff recommendations and present testimony on electric resource planning, rate design, special contracts, energy efficiency programs, and other matters. Responsible for maintaining and operating UPLAN, a computer model of electricity supply and production costs.

Arizona Department of Economic Security, Research Administration, Economic Analysis Unit: Labor Market Information Supervisor (September 1985-August 1989), Research and Statistical Analyst (September 1984-September 1985), Administrative Assistant (September 1983-September 1984). Supervised professional staff engaged in economic research and analysis. Responsible for occupational employment forecasts, wage surveys, economic development studies, and over 50 publications. Edited the monthly **Arizona Labor Market Information Newsletter**, which was distributed to about 4,000 companies and individuals.

Testimony

Resource Planning for Electric Utilities (Docket No. U-0000-90-088), Arizona Corporation Commission, 1990; testimony on production costs and system reliability.

Trico Electric Cooperative Rate Case (Docket No. U-1461-91-254), Arizona Corporation Commission, 1992; testimony on demand-side management and time-of-use and interruptible power rates.

Navopache Electric Cooperative Rate Case (Docket No. U-1787-91-280), Arizona Corporation Commission, 1992; testimony on demand-side management and economic development rates.

Arizona Electric Power Cooperative Rate Case (Docket No. U-1773-92-214), Arizona Corporation Commission, 1993; testimony on demand-side management, interruptible power, and rate design.

Tucson Electric Power Company Rate Case (Docket Nos. U-1933-93-006 and U-1933-93-066) Arizona Corporation Commission, 1993; testimony on demand-side management and a cogeneration agreement.

Resource Planning for Electric Utilities (Docket No. U-0000-93-052), Arizona Corporation Commission, 1993; testimony on production costs, system reliability, and demand-side management.

Duncan Valley Electric Cooperative Rate Case (Docket No. E-01703A-98-0431), Arizona Corporation Commission, 1999; testimony on demand-side management and renewable energy.

Tucson Electric Power Company vs. Cyprus Sierrita Corporation, Inc. (Docket No. E-0000I-99-0243), Arizona Corporation Commission, 1999; testimony on analysis of special contracts.

Arizona Public Service Company's Request for Variance (Docket No. E-01345A-01-0822), Arizona Corporation Commission, 2002; testimony on competitive bidding.

Generic Proceeding Concerning Electric Restructuring Issues (Docket No. E-00000A-02-0051), Arizona Corporation Commission, 2002; testimony on affiliate relationships and codes of conduct.

Tucson Electric Power Company's Application for Approval of New Partial Requirements Service Tariffs, Modification of Existing Partial Requirements Service Tariff 101, and Elimination of Qualifying Facility Tariffs (Docket No. E-01933A-02-0345) and Application for Approval of its Stranded Cost Recovery (Docket No. E-01933A-98-0471), Arizona Corporation Commission, 2002, testimony on proposals to eliminate, modify, or introduce tariffs and testimony on the modification of the Market Generation Credit.

Arizona Public Service Company's Application for Approval of Adjustment Mechanisms (Docket No. E-01345A-02-0403), Arizona Corporation Commission, 2003, testimony on the proposed Power Supply Adjustment and the proposed Competition Rules Compliance Charge.

Generic Proceeding Concerning Electric Restructuring Issues, et al (Docket No. E-00000A-02-0051, et al), Arizona Corporation Commission, 2003-2005; Staff Report and testimony on Code of Conduct.

Arizona Public Service Company Rate Case (Docket No. E-01345A-03-0437), Arizona Corporation Commission, 2004; testimony on demand-side management, system benefits, renewable energy, the Returning Customer Direct Assignment Charge, and service schedules.

Arizona Electric Power Cooperative Rate Case (Docket No. E-01773A-04-0528), Arizona Corporation Commission, 2005; testimony on a fuel and purchased power cost adjustor, demand-side management, and rate design.

Trico Electric Cooperative Rate Case (Docket No. E-01461A-04-0607), Arizona Corporation Commission, 2005; testimony on the Environmental Portfolio Standard; demand-side management; special charges; and Rules, Regulations, and Line Extension Policies.

Arizona Public Service Company (Docket Nos. E-01345A-03-0437 and E-01345A-05-0526), Arizona Corporation Commission, 2005; testimony on the Plan of Administration of the Power Supply Adjustor.

Arizona Public Service Company Emergency Rate Case (Docket No. E-01345A-06-0009), Arizona Corporation Commission, 2006; testimony on bill impacts.

Arizona Public Service Company Rate Case (Docket Nos. E-01345A-05-0816, E-01345A-05-0826, and E-01345A-05-0827), Arizona Corporation Commission, 2006; testimony on funding for renewable resources, net metering, green pricing tariffs, and a Power Supply Adjustor surcharge.

Tucson Electric Power Company Filing to Amend Decision No. 62103 (Docket No. E-01933A-05-0650), Arizona Corporation Commission, 2007, testimony on demand-side management, time-of-use, direct load control, and renewable energy.

Consideration, Pursuant to A.R.S. § 40-252 to Modify Decision No. 67744 Relating to the Self-Build Option (Docket No. E-01345A-07-0420), Arizona Corporation Commission, 2008, testimony on the self-build option for Arizona Public Service Company.

Sempra Energy Solutions Application for Certificate of Convenience and Necessity (Docket No. E-03964A-06-0168), Arizona Corporation Commission, 2008, testimony on the overall fitness of Sempra Energy Solutions to provide competitive retail electric service in Arizona.

Tucson Electric Power Company rate case (Docket No. E-01933A-07-0402), Arizona Corporation Commission, 2008, testimony in support of the Settlement Agreement regarding renewable energy, demand-side management, Rules and Regulations, partial requirements service tariffs, interruptible tariff, demand response, and bill estimation.

Arizona Public Service Company rate case (Docket No. E-01345A-08-0172), Arizona Corporation Commission, 2009, testimony in support of the Settlement Agreement regarding

Power Supply Adjustment Plan of Administration, treatment of Schedule 3, withdrawal of APS' Impact Fee proposal, withdrawal of APS' System Facilities Charge proposal, revisions to Schedule 3, demand-side management, and renewable energy.

Publications

Author of the following articles published in the *Arizona Labor Market Information Newsletter*:

"1982 Mining Employees - Where are They Now?" - September 1984
"The Cost of Hiring" and "Arizona's Growing Industries" - January 1985
"Union Membership - Declining or Shifting?" - December 1985
"Growing Industries in Arizona" - April 1986
"Women's Work?" - July 1986
"1987 SIC Revision" - December 1986
"Growing and Declining Industries" - June 1987
"1986 DOT Supplement" and "Consumer Expenditure Survey" - July 1987
"The Consumer Price Index: Changing With the Times" - August 1987
"Average Annual Pay" - November 1987
"Annual Pay in Metropolitan Areas" - January 1988
"The Growing Temporary Help Industry" - February 1988
"Update on the Consumer Expenditure Survey" - April 1988
"Employee Leasing" - August 1988
"Metropolitan Counties Benefit from State's Growing Industries" - November 1988
"Arizona Network Gives Small Firms Helping Hand" - June 1989

Major contributor to the following books published by the Arizona Department of Economic Security:

Annual Planning Information - editions from 1984 to 1989
Hispanics in Transition - 1987

(with David Berry) "Contracting for Power," *Business Economics*, October 1995.

(with Robert Gray) "Customer Selection Issues," *NRRI Quarterly Bulletin*, Spring 1998.

Reports

(with Task Force) *Report of the Task Force on the Feasibility of Implementing Sliding Scale Hookup Fees.* Arizona Corporation Commission, 1992.

Customer Repayment of Utility DSM Costs, Arizona Corporation Commission, 1995.

(with Working Group) *Report of the Participants in Workshops on Customer Selection Issues*," Arizona Corporation Commission, 1997.

"DSM Workshop Progress Report," Arizona Corporation Commission, 2004.

(with Erin Casper) "Staff Report on Demand Side Management Policy," Arizona Corporation Commission, 2005.

"Staff Report on Interconnection for the Generic Investigation of Distributed Generation," Arizona Corporation Commission, 2007.